Information Request TEC-3-1

Referring to Mr. LaMontagne's Rebuttal Testimony at p. 12, line 7, please define "non-coincident peak basis." Does non-coincident peak refer to the customer's contribution to class peak, or the individual customer's maximum annual demand?

Response

The reference to non-coincident peak means the individual customer's maximum annual demand.

Information Request TEC-3-2

Referring to Mr. LaMontagne's Rebuttal Testimony at p. 12, lines 17 and 18, provide the basis for Mr. LaMontagne's assertion that DG customers will forgo generation in order to profit from selling gas in the market. Identify any specific DG customers known to Mr. LaMontagne within the NSTAR service territory who have forgone generation in order to sell natural gas in the market.

Response

Mr. LaMontagne is not aware of any such specific customer. However, there are significant economic incentives for a customer to engage in such a strategy since electricity prices are averaged over many hours and peak-period gas prices may be far higher than the regulated electricity prices. This is particularly true during periods of high demand in the winter. In fact, we are aware of a large QF that significantly reduced its availability because of the opportunity to sell gas at high market prices.

Information Request TEC-3-3

Referring to Mr. LaMontagne's Rebuttal Testimony at p. 15, line 11, provide the basis for the statement that "most customers will install DG to satisfy base load requirements."

Response

It is generally most economical, in terms of energy costs savings through displacement, for customers to install on-site generation capacity to serve loads that are sustained for many hours in the year. The threshold point for the ideal amount of capacity to install is the load level on the annual load duration curve corresponding to the number of hours of operation where the purchased power cost curve intersects with the on-site generation total cost curve. That capacity level is often referred to as base load.

Information Request TEC-3-4

Please provide a copy of all load studies Mr. LaMontagne has performed or reviewed comparing the load characteristics of DG customers with the load characteristics of non-DG customers.

Response

Please refer to the response to Information Request TEC-3-5, which sets forth the tabulation of the AVGBQ/MAXBQ ratio for customers with and without on-site generation.

Information Request TEC-3-5

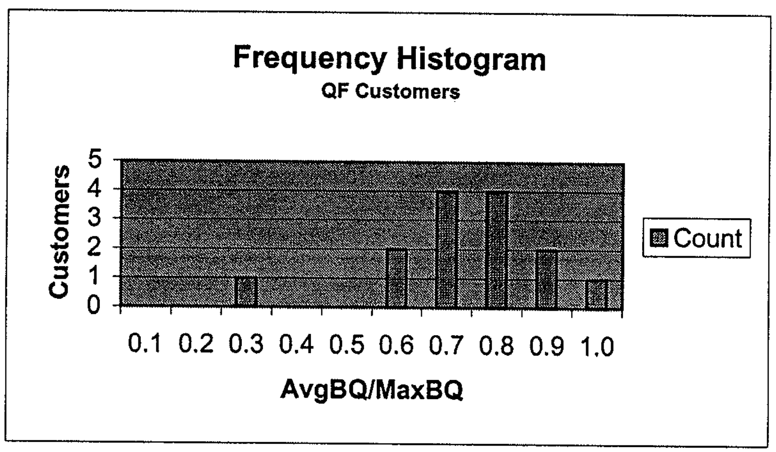
For the 15 customers (excluding MIT) with generation identified in the supplemental response to TEC 2-1, please provide the monthly billing demands and the ratio of average to maximum as shown in Exhibit NSTAR-HCL-8.

Response

Please see Attachment TEC-3-5.

Company	Rate	MaxBQ	MinBQ	MIN/Max	Gen-Cap	kWh	Days	AvgBQ	AvgKW	LF	AvgPF	Max/Avg	Avg/Max
COM	Rate G-3	1,621	190	0.117	1,050	3,049,800	368	841	940	0.224	95.5	1.929	0.519
COM	Rate G-2	1,285	437	0.340	200	3,099,960	364	842	935	0.206	96.6	1.526	0.655
COM	Rate G-2	529	365	0.690	200	1,554,120	368	413	380	0.353	91.0	1.281	0.781
BECO	Rate G-3	733	171	0.233	600	2,203,200	367	565	565	0.342	82.7	1.296	0.772
BECO	Rate G-3	2,336	1,798	0.770	70	7,624,080	366	2,003	2,003	0.372	84.0	1.166	0.858
BECO	Rate G-3	1,830	1,660	0.907	1,800	13,191,360	364	1,746	1,746	0.825	89.9	1.048	0.954
BECO	Rate T-2	1,776	42	0.023	250	1,201,760	335	470	470	0.084	92.5	3.780	0.265
BECO	Rate T-2	121	51	0.421	75	174,060	365	76	76	0.164	89.0	1.588	0.630
BECO	Rate T-2	512	252	0.493	600	1,620,360	369	342	342	0.358	87.2	1.496	0.669
BECO	Rate T-2	235	85	0.363	75	388,720	362	160	160	0.191	78.6	1.471	0.680
BECO	Rate T-2	734	382	0.520	105	2,999,040	363	516	516	0.469	97.2	1.424	0.702
BECO	Rate T-2	984	641	0.652	75	5,103,420	367	781	781	0.589	94.4	1.259	0.795
BECO	Rate T-2	545	321	0.589	250	1,246,360	363	459	459	0.263	89.6	1.186	0.843
BECO	Rate T-2	664.3	202.6	0.304983	75	1,689,440		353.8				1.877614	0.533

Count	Avg/Max Bin
0	0.1
0	0.2
1	0.3
0	0.4
0	0.5
2	0.6
4	0.7
4	0.8
2	0.9
1	1.0
0	>1.0
14	Total



Information Request TEC-3-6

Referring to Mr. LaMontagne's Rebuttal Testimony at p. 24, line 11, define "a standby service customer's non-coincident peak distribution requirements." State whether "non-coincident peak" refers to the customer's individual maximum demand or the customer's contribution to class peak demand.

Response

Non-coincident peak refers to the individual customer's maximum demand.

Information Request TEC-3-7

Referring to Mr. LaMontagne's Rebuttal Testimony at p. 27, lines 11 and 12, describe "enforceable, technical ability."

Response

By "enforceable, technical ability", the Company means it would be required to have the physical assurance that the load in excess of the firm level of the standby service contract demand is either reduced by the customer or is disconnected from the distribution system.

Information Request TEC-3-8

Referring to Mr. LaMontagne's Rebuttal Testimony at p. 29, lines 9 and 10, provide the basis for the proposal to include "a 20% threshold for the applicability of standby service."

Response

The 20 percent threshold is currently included in the Cambridge's Rate SB-1. In addition, the 20 percent level is supported by the information in Exhibit NSTAR-HCL-8. The information on this exhibit indicates that the variability of billing demands for most customers without on-site generation is between 10 percent and 30 percent. Thus, setting the minimum on-site generation capacity at 20 percent is reasonable.

Information Request TEC-3-9

Has Mr. LaMontagne ever used maximum customer demand as an allocator for distribution plant in an embedded cost of service study for one of the NSTAR companies? Assume maximum customer demand is the sum of the individual customer peaks in the class in the test year. If Mr. LaMontagne has ever used such an allocator, identify the company, the date of the study, and the specific three-digit account numbers (accounts 360 to 373) to which he applied the allocator. Provide a copy of the study.

Response

Mr. LaMontagne has used non-coincident class demands, but not a maximum customer demand as an allocator in an allocated cost study. A maximum customer demand allocator would be appropriate when performing cost allocations to customer classes when non-continuous-use customers are included either as a separate customer class or combined with a continuous-use customer class.

Information Request TEC-3-10

Referring to Mr. Salamone's Rebuttal Testimony at p. 4, line 10, define "non-coincident peak demands of all customers on the circuit."

Response

The non-coincident peak demand of a customer is the maximum peak demand of that customer. The non-coincident peak demand of all customers on a circuit is the sum of each customer's individual maximum peak demand.

Information Request TEC-3-12

In planning for a distribution circuit, does Mr. Salamone consider load growth and reserve margins? If so, please state the range of the specific assumptions Mr. Salamone has used in planning studies.

Response

Yes, both load growth and reserve margins are considered in the planning process. The range of load growth varies for each distribution circuit, but on average, load growth has averaged approximately 2 percent. The general rule of thumb is to design a circuit with between 50 percent and 20 percent reserve margin. This allows the circuit to provide backup capacity in support of adjacent circuit outages.

Information Request TEC-3-13

In planning for a distribution substation, does Mr. Salamone consider load growth and reserve margins? If so, please state the range of the specific assumptions Mr. Salamone has used in planning studies.

Response

Yes, both load growth and reserve margins are considered in planning studies for distribution substations. The range of load growth varies for each distribution substation, but on average, load growth has been approximately 2 percent, Reserve margins range from 40 percent to 20 percent.

Information Request TEC-3-24

Referring to Ms. Parmesano's Rebuttal Testimony at page 6, lines 17-20, please explain how the current structure of rates for customers without generation does not provide signals to DG customers of the costs of providing standby service both in terms of (a) maintaining the necessary infrastructure; and (b) delivering the energy when the customer's generation is not producing at the normal level.

Response

The current structure of rates for customers without generation charges for the infrastructure on a usage basis, so that on these rates customers with on-site generation, whose metered use is only sporadic, do not pay the full cost of the infrastructure standing ready to serve them. Meanwhile, under these rates, DG standby usage triggers charges that exceed the cost of the actual energy deliveries because the usage charges include infrastructure costs.

Information Request TEC-3-25

Referring to Exhibit NSTAR-HSP-2 at p.5, please provide all supporting data for the statement: "Customers with DG may have load characteristics that are very different from those of customers that purchase all their electricity requirements."

Response

The statement is not based on specific data, but rather on the knowledge that, given the wide range of technologies, operating patterns, outage rates, and residual customer loads, there is a potential for on-site generating customers to have load characteristics very different from continuous use customers. Moreover, on-site generating customers have lower load factors than continuous-load customers because of their intermittent use.

Information Request TEC-3-26

Please provide all data examined or utilized by Ms. Parmesano regarding the load characteristics of existing customers with generation in NSTAR's service territory.

Response

Dr. Parmesano did not examine or use any such data.

Information Request TEC-3-27

Please provide all testimony and supporting exhibits by Ms. Parmesano regarding electric standby rates from January 1, 1999 to the present. Please also supply transcripts of cross-examination and copies of regulatory decisions relating to this testimony.

Response

Dr. Parmesano has not filed testimony on standby rates from January 1, 1999 to the present, except for this case.

Information Request TEC-3-28

Please provide all testimony and supporting exhibits by Ms. Parmesano regarding ratchets in electric rates from January 1, 1999 to the present. Please also supply transcripts of cross-examination and copies of regulatory decisions regarding this testimony.

Response

Dr. Parmesano has not filed testimony on ratchets in electricity rates from January 1, 1999 to the present.

Information Request TEC-3-29

Referring to Ms. Parmesano's Rebuttal Testimony at p. 11, lines 6-9, please provide a copy of the Department approved cost studies that are the basis of the current unbundled distribution rates of the three NSTAR utilities. Please show how these cost studies were unbundled into components.

Response

Please see responses to Information Requests: NEDGC-1-1, DTE-2-23, DTE 3-18 and DTE 4-19.

Information Request TEC-3-30

Has Ms. Parmesano advocated using maximum customer demand as an allocator for distribution plant in an embedded cost of service study for a client? Assume maximum customer demand is the sum of the individual customer peaks in the class in the test year. If so, list the utility, the date of the study, and the specific three-digit account numbers (accounts 360 to 373) for which the allocator was proposed. Provide a copy of any study using such recommended allocator.

Response

Dr. Parmesano has not previously testified that maximum customers demand should be the appropriate allocator for distribution plant in an embedded cost of service study.

Information Request TEC-3-31

Please provide a copy of "Alternative Approaches to Area-Specific Marginal Transmission and Distribution Cost Estimation" (1994 EPRI presentation).

Response

A copy is provided as Attachment TEC-3-31.

ALTERNATIVE APPROACHES FOR AREA-SPECIFIC MARGINAL TRANSMISSION AND DISTRIBUTION COST ESTIMATION

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Abstract

For a variety of reasons, there is growing interest by the electric utility industry in marginal and avoided transmission and distribution (T&D) cost estimates that reflect the different capacity (and cost) situations in various parts of the utility's service territory. Geographically-differentiated T&D costs can improve the efficiency of DSM program evaluations, special rates and contracts, and standard tariffs. This paper looks at area-specific T&D cost efforts by three utilities -- Pacific Gas & Electric Company, Public Service Electric & Gas Company of New Jersey, and Central Maine Power Company. Each company has made major contributions to a relatively neglected area of marginal cost analysis, and each company's approach could be improved by borrowing from the others' efforts. The paper also suggests that a different approach -- estimating area-specific short-run marginal T&D costs may provide even more useful information for use in rates and DSM evaluations.

Introduction

For a variety of reasons, there is growing interest by the electric utility industry in marginal and avoided transmission and distribution (T&D) cost estimates that reflect the different capacity (and cost) situations in various parts of the utility's service territory. Demand-side management can be targeted to areas where it will be most cost-effective if avoided T&D costs are geographically differentiated. The charges in special rates or contracts to encourage economic development or load retention can be varied geographically to encourage load development and retention in the areas where it can be served at lowest cost. Geographically differentiated T&D cost estimates are important in the design of efficient wheeling rates. Geographically-differentiated standard tariffs based on marginal costs, if politically acceptable, can give customers more efficient price signals than rates based on non-geographically-differentiated marginal costs.

Utility cost analysts have spent years perfecting methods for estimating marginal and avoided generation costs. Until recently, there has been significantly less effort spent on methods for marginal T&D costing. This paper describes and evaluates approaches being explored by three U.S. utilities to improve their marginal T&D estimates.

Characteristics of Appropriate T&D Cost Estimates

To design appropriate methods for estimating T&D costs it is necessary to first determine the purpose for which the estimates are to be used. The average T&D costs avoided because of a large reduction, for a specific period of time, in the load that would otherwise exist in a given area may be quite different from the T&D cost associated with a small increase in load, evaluated one year at a time. The first estimate might be used to evaluate the benefits of a particular demand-side management (DSM) program.[1] The second would be appropriate for setting efficient rates.

T&D Costs for DSM Evaluations

If we assume that the evaluation of DSM programs requires an estimate of the average avoided cost associated with a particular program or group of programs, then the avoided cost T&D method should have the following characteristics:

1. Be area specific. Avoided T&D costs may vary significantly across the service territory.
2. Take the size of the load reduction into account. Average avoided costs per kilowatt may vary significantly depending on the size of the load reduction.
3. Reflect the specific period of years over which the program's effects are expected to persist.
4. Be time-differentiated. A program which reduces load only in the summer peak period may have an effect on costs very different from a program which reduces load in all periods.
5. Reflect the timing of planned capacity additions (and the degree of excess capacity in the near-term).
6. Reflect the rising value of load reduction as inflation raises the cost of new capacity.
7. Take uncertainty into account. Avoided costs are future costs and cannot be known precisely.

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[1] For efficiency, the cost of the last increment of the large DSM program should be compared to the <u>marginal</u> benefits it will provide, not to the average avoided cost for the entire block. If the cost of the last increment of the program is not less than or equal to the cost avoided by that last increment of program, the proposed program is too large. Typically, however, this marginal analysis is not performed and large programs, or groups of programs, are instead compared to the average avoided cost for the entire block of load reduction.

T&D Costs for Ratemaking

Most of the characteristics of T&D cost estimates needed for marginal cost ratemaking are the same as those needed for DSM avoided cost computations. However, there are two important differences. The first difference is in item number 2, above. By definition, marginal cost is the change in total cost with respect to a very small change in load. If the rates based on new, more precise marginal T&D cost estimates are expected to generate such a large customer response that marginal costs change, it is important to simulate several iterations of marginal cost estimates and customer responses. However, once an equilibrium "base case" is identified, the marginal cost method should examine the effect on total cost of a small change in that base case.

The second difference between the characteristics of appropriate T&D methods for DSM evaluations and marginal cost ratemaking is the period of analysis. To evaluate the effect of a particular DSM program, we need to track changes in cost over the expected effective period of that program (and beyond if differences in costs between the base case and DSM case persist even after the program's effects have worn off.) Experts differ over the period that should be reflected in the marginal cost price signals. Some, like me, urge utilities to base rates on the marginal costs in the period the rates are expected to be in effect and tell customers through other means of communication the rates they can expect in the future. Others believe that customers should pay rates that reflect the marginal costs expected to be incurred over a specific period of years, such as five, ten, or more.[2] To accommodate all of these philosophies, a marginal cost study should produce individual cost estimates for every year over a period of ten or more years. These annual cost estimates can then be combined as the ultimate decision-makers, the regulators, see fit.

Because the agenda of this conference focusses on innovative electricity pricing, the remainder of this paper will address T&D costing methods for use in ratemaking, rather than in DSM evaluations or other uses of avoided cost analysis.

Initial Attempts at Area-Specific Marginal T&D Costing

A number of utilities have begun to develop methods for estimating area-specific marginal or avoided T&D costs. Some of these methods are still in the early stages of development, while others have actually been used in regulatory proceedings. Below are descriptions and

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[2] Some rate analysts believe that rates should reflect theoretical long-run marginal costs, i.e., the marginal costs that would be incurred to serve additional load if the utility system were optimal and had no excess or shortage of capacity. Since this extreme approach is antithetical to the move toward area-specific marginal costs that reflect the real resource costs or savings associated with load changes, it will not be addressed in this paper.

evaluations of efforts by three utilities -- Pacific Gas & Electric Company, Public Service Electric & Gas Company of New Jersey, and Central Maine Power Company.

The PG&E Approach

In its Test-Year 1993 General Rate Case, Pacific Gas & Electric Company (PG&E) proposed a new approach to estimating marginal T&D costs that they call the Present Worth (PW) Method.[3] The method was proposed for assigning the overall revenue requirement to classes based on an equiproportional adjustment of the marginal costs of serving each class, but not for developing geographically-differentiated rates.

PG&E's new method is based on the assumption that a nine-year reduction in the load forecast equal to the average annual load growth expected over those nine years will cause a shift of the nine-year capacity expansion plan by one year. Projects are categorized as bulk projects, applying to all areas; regional projects, applying to all districts within a division, district projects related to growth only within the district; and non-specific background projects, the costs of which are assigned to districts based on relative expected load growth.[4]

PG&E's goal was to develop a method that would reflect the lumpiness of transmission investment and the position of the utility in its cycle of T&D capacity building in the various districts of the service territory. For example, if unusually heavy investment is expected in the next two years, PG&E wanted a marginal/avoided method that would result in higher cost estimates than if the heavy investment were planned for years 7 and 8. The PW method computes the real levelized annual savings per kilowatt from shifting an expansion plan by one year. The computation is essentially performed for three overlapping nine-year periods and averaged.

Table 1 illustrates the PG&E PW method using one of PG&E's division transmission projects serving several districts, but with the simplification of eliminating the three-period average and concentrating on a single nine-year period, 1990-1998. The budgeted expenditures for the San Francisco Near-Term Substation Reinforcement project, shown in Col. (A) are assumed to shift by one year, shown in Col. (D) in response to a load reduction equal to the average annual expected load growth over the nine-year period, in

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[3] This description of PG&E's proposed area transmission analysis is based on Exhibit PG&E-16 from PG&E's Application No. 91-11-036 to the California Public Utilities Commission, November 26, 1991.

[4] No cost of background projects is allocated to a district with expected load growth of less than 0.5 megawatts per year.

this case 13 megawatts, shown in Col. (C). Cols. (E) and (F) show the two investment streams scaled to convert the investment dollars to revenue requirements, including return, depreciation, taxes, operation and maintenance expense (O&M), and general plant and administrative and general adders. Line (13) shows the present value of the two streams of revenue requirements. The difference in the two streams is divided by the average annual load growth for the nine-year period on Line (14). The final two steps are to convert this present value of revenue requirement per kilowatt to the first-year value of a stream of values that rise at the rate of inflation (Line (15) and convert it to 1993 dollars on Line (16)).

In the actual PG&E method, the process shown in Table 1 is repeated twice more, once for the period 1991-1999 and again for the period 1992-2000. The results for all three periods are averaged. The three-period process is also repeated for bulk transmission projects, district projects, and non-specific background projects. All of the costs applicable to a given district are summed to yield a district-specific marginal/avoided cost estimate.

The PSE&G Approach

Public Service Electric & Gas Company of New Jersey (PSE&G) is also working on a method for developing area-specific marginal transmission costs.[5] PSE&G has concentrated on determining the contribution of load growth at various substations to the need for the budgeted transmission projects. A substation can be physically close to a transmission line that is overloaded, but electrically remote. This means that load growth at the substation is not contributing to the need for the investment designed to relieve the congestion. Conversely, a substation can be physically remote from a planned transmission upgrade, but electrically close. For some projects it is obvious which substations' incremental loads have the largest impact on the need for the investment, but for many projects, an objective measure is needed.

Transmission engineers at PSE&G and other PJM pool companies use "generation distribution factors" (or GEN DFAX) to represent the portion of generation at a particular bus that appears on a transmission line. According to PSE&G, these factors are developed by loadflow software and are based solely on the transmission network topology, not the load level, generation dispatch or individual line loadings. These factors are used by a loadflow program to screen a load flow base case for potential overloads as a result of a sudden line outage or shift in generation dispatch.

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5 This description of the PS&EG work-in-progress is based on Robert Stack, "An Area-Specific Transmission Marginal Costing Methodology," Public Service Electric and Gas Company, presented at the NERA Marginal Cost Working Group meeting in Portland, Maine, October 1993.

While the GEN DFAX tells what portion of the marginal generation at a particular bus will flow on a given transmission line, treating load at the transmission substations as negative generation and reversing the sign of the GEN DFAX values for the substations tells the portion of incremental load at each substation that will be met by deliveries over a particular transmission line. Thus, reversing the sign of the GEN DFAX values gives LOAD DFAX values.

PSE&G's proposed method for area transmission marginal costing involves using the LOAD DFAX values to determine how many kilowatts of load growth triggered the capacity addition so that the dollars of investment can be converted to dollars per kilowatt, and to assign marginal responsibility for the budgeted projects to substations (and ultimately larger regions of the service territory). The first step is to calculate the LOAD DFAX values assuming the network conditions (generally first contingency) that result in the overload that triggers the budgeted transmission project, and rank the substations in descending order by LOAD DFAX. These values range from -1 to 1, with negative values indicating that added load at a particular substation would reduce load on the overloaded facility.

Table 2 shows the LOAD DFAX values for a particular 230-kV upgrade project and the computation of the load growth that triggered it. The LOAD DFAX of 0.746 in Col. (2) on the first line shows that a kilowatt of load growth at the Sunnymead substation will increase load on the Branchburg-Bridgwater line by 0.746 kilowatts under first contingency conditions. Under the assumption that the upgrade will accommodate load growth for ten years, PSE&G has estimated what that ten-years of load growth on the Branchburg-Bridgwater circuit will be. Col. (3) shows the estimated load growth for each substation. Col. (5) uses the coincidence factors in Col. (4) to convert the non-coincident substation load growth to load growth at the time of the system peak.[6] Col. (6) then computes the growth in peak on the Branchburg-Bridgwater circuit over the ten-year period by multiplying the coincident growth at each substation by its LOAD DFAX, and summing across all substations. The final step in the process of evaluating the cost per kilowatt of this upgrade is to divide the cost of the project by the load growth on the circuit, for a project average investment cost of $90.80 per kilowatt of added flow.

Now that we know the cost per kilowatt of this particular upgrade, we need to determine how much of this cost is triggered when load grows in a particular region. Table 3 shows the substations grouped by LOAD DFAX and physical proximity. In Col. (3) the ten-year incremental contribution to flows on the Branchburg-Bridgwater circuit by the substations in the area is divided by the ten-year coincident peak load growth by these substations to yield a load-growth-weighted area LOAD DFAX. Multiplying these area LOAD DFAX by

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[6] Loads on the Branchburg-Bridgwater circuit are expected to peak at the time of the overall system peak.

the average investment cost per kilowatt of added flow on the circuit (calculated on Table 2), gives, in Col. (4), the area-specific marginal investment per kilowatt of load growth related to the project.

PSE&G's plan is to focus next on a method for integrating the marginal costs of several projects, taking into account the fact that some projects are triggered by off-peak loads.

The CMP Approach

In Case 89-68, the Maine Public Utilities Commission asked Central Maine Power Company (CMP) to consider alternative approaches to estimating marginal transmission and distribution costs. The Commission was particularly interested in sensitivity studies of transmission and distribution costs. The Commission also suggested that marginal T&D costs should reflect the timing of future capacity additions.[7]

As part of its transmission planning process, CMP prepares detailed studies of current and future (ten-year) transmission needs for each of its 14 planning areas. The areas are defined based on load, transmission and geographic characteristics. A new Area Study is prepared for each area every three or four years. CMP is exploring the use of information in the area studies to develop marginal transmission costs.

Table 4 illustrates CMP's early work on this method.[8] Using the analysis in the Area Study, two transmission plans are prepared for an area, one based on the assumption that load growth will be approximately one percent per year, and a second based on the assumption that load will grow at approximately three percent per year.[9] Projects are defined as related to load growth (G), related to projects needed to serve current load but delayed for some reason (L), projects needed for safety reasons (S), and replacement/rebuild projects (R). Only the projects needed for additional growth are considered marginal.

Cols. (4) and (7) of Table 4 show the transmission investment in nominal dollars for the one-percent and three-percent growth scenarios, respectively. Cols. (5) and (8) convert the

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7 Maine Public Utilities Commission, Order for Docket 89-68, Issued March 29, 1991.

8 This description is based on the prefiled direct testimony of Waine Whittier and Attachment A to the prefiled direct testimony of Steven Garwood in Maine Public Utilities Commission Docket No. 92-315, filed February 17, 1993.

9 The loads in both scenarios are also adjusted for specific known changes due to factors such as major new customers.

investment to 1993 present value terms. The last line of Table 4 shows the present value investment per kilowatt of load growth for the one-percent, three-percent, and extra two-percent above the one-percent case.

In an interim filing in its latest rate structure case, CMP filed a system-wide marginal cost estimate based on Area Studies recently completed for 7 of its 14 areas. In that filing, CMP computed the present value of transmission investment per kilowatt of load growth for the combined 7 areas for the one-percent and three-percent growth scenarios, and interpolated to find a value corresponding to a 1.5-percent growth rate, which is consistent with the load forecast used in the generation capacity portion of the marginal cost analysis. This marginal investment per kilowatt of load growth was then converted to an annual value by applying an economic carrying charge, fixed O&M factors, allowance for working capital, and loaders for A&G and general plant.

Evaluation of Emerging Methods

PG&E

The new PG&E PW approach is an important step forward in marginal T&D costing. It reflects the geographic differences in the costs imposed when load grows and reflects the timing of those cost effects. I do, however, have a number of criticisms of the method.

The most important assumption underlying the PW method is that if load growth declined for nine years by an amount equal to the average annual load growth expected over the nine-year period, the entire capacity expansion plan for those nine years would slip by exactly one year. I think it is inappropriate to make this assumption without checking with the planners who developed the expansion plan. Perhaps there are expensive projects in the early years that have been deferred because of budget constraints and will be built even if load growth is reduced. Another possibility is that particular projects are needed to meet the remaining load growth and they cannot be deferred without unacceptable effects on reliability.

A second key assumption is that a load reduction equal to a year's worth of load growth provides an appropriate basis for marginal cost. One year's load growth on PG&E's bulk transmission system is approximately 200 megawatts, which is hardly a marginal change. It would be interesting to see what the PG&E planners' response would be to a much smaller change in the load forecast.

PG&E's PW method assumes that the load reduction lasts for exactly nine years. The choice of nine-years was explained as a compromise between giving a short-term and a long-term price signal. In light of PG&E's use of an average of six years of generation capacity costs and a single year of marginal energy costs in its marginal cost analysis, it seems inconsistent to choose a nine-year price signal for transmission and distribution. I favor signaling in rates the marginal costs expected over the period the rates are to be in effect and telling customers directly our best estimates of future prices so that they can efficiently make both short- and long-term consumption decisions.

It is PG&E's position that a load reduction lasting nine years will cause a one-year deferral of projects planned for those nine years, but have no impact on capacity costs beyond the nine-year window. An alternative approach, using an economic carrying charge to compute the value of a one-year deferral, recognizes that a consumption decision which alters the near-term capacity expansion plan will also affect capacity expenditures for many years into the future because the schedule for replacing the deferred projects will be different from the schedule that would have been followed without the deferments. PG&E's view is that capacity is not replaced to continue to serve load indefinitely. This view seems inconsistent with utility actions. If load is not expected to continue at or above the current forecast, a utility would be imprudent to build capacity with an expected life of 40 years.

PG&E's new method assumes that if projected loads are reduced by the average annual amount that loads are expected to grow over the next nine years, the entire capacity expansion plan will be shifted by exactly one year. Because the streams of expenditures are present valued in the analysis, the forecast expenditures in the early years of the period are given more weight than the expenditures in the latter years. However, in the denominator of the equation, the forecast load growth for each year is given equal weight. For consistency in the numerator and denominator, the annual load growth should be discounted by the real discount rate before being averaged.

PG&E's new method uses some historical information. Their transmission budget figures covered the period 1990 to 2000, even though 1990, 1991 and 1992 investments would be sunk by the time the rates went into effect in 1993. Analysis that covers only future investment would more accurately reflect the level and timing of PG&E's marginal costs.

PG&E proposed applying the one-year shift analysis three times, for overlapping nine-year periods, to smooth away some of the lumpiness inherent in the results from their new method and avoid the volatility in rates that might result from using a single nine-year period. Since one of the company's stated goals was to reflect the actual timing of expenditures for new capacity, this averaging technique seems counter-productive.

PSE&G

PSE&G's method for determining the areas in and extent to which load growth is triggering the need for capacity expansion is an important improvement over a more subjective assignment of transmission projects to areas. Furthermore, PSE&G's approach to determining the load growth, however geographically dispersed, that is triggering a particular project is a welcome refinement. This method does depend on the assumption that each project is expected to accommodate projected load growth for ten years. It is possible that some adjustment in the assumed time period should be made for particular projects.

The time frame of PSE&G's analysis is ten years. It will provide, when applied to all planned transmission projects, an estimate of the typical expenditure (over ten years) associated with marginal load in each district. Thus, the method does not contain a mechanism to reflect nearer-term shortages or excesses of transmission capacity, or to track the lumpiness of particular transmission investments.

PSE&G's method for combining the LOAD DFAX for the substations within an area is to weight them by relative load growth over the ten-year planning horizon. This may not provide the "second-best" solution to pricing for groups of substations rather than for individual substations. Even at the substations with low expected growth customers are making marginal consumption decisions and need to face efficient prices. I would propose weighting the individual LOAD DFAX by load, or number of customers served, rather than by load growth.

CMP

CMP's Area Studies approach to marginal transmission costing looks at the planners' actual response to small changes in the load forecast. Thus, it avoids the use of overly simplified rules of thumb and comes close to a truly marginal analysis. By computing the present value of planned investments in a particular area, the method reflects the timing of needed capacity expansion. However, since the load growth is not discounted, there is a problem of inconsistency in the numerator and denominator. The load growth should be discounted by the real discount rate.

In its interim marginal cost filing, CMP interpolated between the incremental investment per kilowatt for one-percent load growth and three-percent load growth to obtain a value for the expected 1.5-percent load growth. In each area studied, the results for a one-percent and a three-percent change in load varied significantly. In some cases small changes in load could be accommodated with minimal investment, while in other cases even low growth would trigger large investments, but further growth would not require much additional capacity. To approximate the cost of a marginal change from the expected 1.5-percent growth rate, I would suggest developing a different method for estimating the marginal cost around the expected level of load growth that would treat the investment necessary for the first one-percent of growth as essentially "sunk."

Summary

All three of the methods described above make major contributions to a relatively neglected area of marginal cost analysis. All three recognize the importance of looking at transmission planning on an area basis, rather than a system-wide basis. All three focus on future projects, treating investment in the recent past as sunk and, therefore, irrelevant to marginal cost. All three screen out projects that are not related to growth, such as replacements and relocations. All three take approximately a ten-year look at marginal costs.

PG&E's work emphasizes development of an easily replicated method that uses only information developed as part of the normal transmission planning process. It relies on simple rules of thumb, such as the assumption that a reduction in load growth for nine years equal to the average annual expected load growth for the period will result in a one-year shift of the entire expansion plan, and that transmission plant does not require replacement, so that there are no "end effects" to account for in comparing the revenue requirements associated with the base case and shift case beyond the nine-year period.

PSE&G's work also relies on information used on a regular basis by transmission planners. To date the company has focussed on determining at which transmission substations marginal load growth contributes to overloads, and the project-by-project cost of responding to that growth.

CMP's work uses detailed Area Studies prepared for transmission planning purposes, and tests the responsiveness of planned investments to alternative forecasts of load growth. This approach does not require the simplifying assumptions used by PG&E, but does require direct assistance from the transmission engineers.

Conclusions

PG&E, PSE&G and CMP have made major contributions to advancing the state of the art in marginal T&D costing. By combining the best features of each company's work, even more precise marginal cost estimates may be possible. For example, area studies like CMP's, based on alternative (and relatively small) changes in load forecast, would obviate the need for some of PG&E's simplifying assumptions about the size and length of the load decrement needed to shift the expansion plan by one year. PSE&G's LOAD DFAX analysis allows for an objective identification of the location of load growth associated with specific planned projects and a more precise estimate of the size of the load growth triggering capacity expansion.

There is another avenue for marginal T&D costing that these three companies have not, to my knowledge, explored. PG&E and a number of other utilities around the country have moved to a short-run approach for estimating marginal generation capacity costs. Instead of tracking the typical cost per kilowatt of generation capacity expansion (net of fuel savings) or discounting the cost of planned future capacity additions, they are estimating the shortage costs (outage costs and/or emergency purchase costs) associated with marginal load. In the short-run, when capacity is not fully variable, load growth cannot be matched by capacity. Rather, there is a change in the expected level of system reliability. That change can be quantified by examining the costs to customers of outages and the costs of emergency purchases that may be made to prevent those outages. If we know what the cost of an unserved kilowatt-hour costs, then we need only an estimate of the number of additional unserved kilowatt-hours that would be triggered by load growth in a particular area at a particular time to determine short-run marginal transmission and distribution costs. I hope to be able to report to you on another occasion about my work on this approach to area-specific, short-run marginal T&D costing.

Table 1

Simplified Illustration of PG&E's PW Method Using San Francisco Near-Term Substation Reinforcement Project (Actual Method Uses A Three-Year Moving Average Of This Computation)

		Annual Investment ($ 000)	Division System Peak (MW)	Load Growth (MW)	Annual Investment Shifted One Year[1] ($ 000)	Scaled PV of Revenue Requirement[2] ($ 000) (A) x 2.356	Scaled PV of Revenue Requirement[2] Shifted One Year ($ 000) (D) x 2.356	Difference in Present Value Streams (1991 $000) (E)-(F)
		(A)	(B)	(C)	(D)	(E)	(F)	(G)
(1)	1990		1,097					
(2)	1991	$640	1,110	13		$1,508	$0	
(3)	1992	4,800	1,123	13	$669	11,309	1,576	
(4)	1993	840	1,136	13	5,016	1,979	11,818	
(5)	1994	0	1,149	13	878	0	2,068	
(6)	1995	0	1,162	13	0	0	0	
(7)	1996	0	1,175	13	0	0	0	
(8)	1997	0	1,188	13	0	0	0	
(9)	1998	0	1,201	13	0	0	0	
(10)	1999	0	1,214	13	0	0	0	
(11)	2000				0			
(12)	Average			13				
(13)	Present Value @ 11%[3] (1991 000$):					$13,302	$12,523	$779
(14)	PV Difference per kW of Load Growth (1991$) (13)/(12)							$59.92
(15)	Real Levelized Annual Cost[4] (1991$/kW)							$9.29
(16)	Real Levelized Annual Cost (1993$/kW) (15) x (1+i)^2							$10.15

Assumptions:	
Inflation Rate (i)	4.5%
Discount Rate (r)	11.0%
Annualized Period	9 years

Area Transmission Scaler for Substations[2]: 2.356

Notes:
[1] Values from columns (1) and (2) shifted one year forward with inflation added.
[2] Scaling converts investment to present valued revenue requirement including return, depreciation, taxes, O&M, and general plant and A&G loaders.
[3] First year is not discounted.
[4] (14) x (r−i) x {1 / [1 − {(1+i) / (1+r)} ^ 9]} −− first year is discounted.

Source: Based on PG&E 1993 Test Year General Rate Case Workpapers, Application, Exhibit (PG&E.16), Chapter 4, pages 1−4 to 1−6.

Illustration of PSE&G Method for Determining a Transmission Project's Cost Per Kilowatt of Contributing Load Growth Upgrade of Branchburg–Bridgewater 230–kV Circuit Project

Bus Name		Generation DFAX	Load DFAX	1992–2002 Station Load Growth (MW)	Substation To System Coincidence Factor	Coincident Substation Load Growth (MW)	Contribution To Branchburg–Bridgewater Line Flow (MW)
			–(1)			(3) x (4)	(2) x (5)
		(1)	(2)	(3)	(4)	(5)	(6)
SUNNYM C	230	–0.746	0.746	6.35	0.797	5.06	3.78
SOMRVLLE	230	–0.612	0.612	24.10	0.797	19.21	11.76
BRIDGWTR	230	–0.537	0.537	–0.90	0.725	–0.65	–0.35
L.NELSN	1	–0.369	0.369	8.30	0.797	6.62	2.44
GREENBK	1	–0.346	0.346	3.80	0.797	3.03	1.05
KILMER I	230	–0.341	0.341	22.00	0.797	17.53	5.98
KILMER W	230	–0.230	0.230	11.90	0.797	9.48	2.18
L.NELSN	1	–0.223	0.223	8.30	0.797	6.62	1.48
GREENBK	1	–0.210	0.210	3.80	0.797	3.03	0.64
CDR GV B	230	–0.090	0.090	3.00	0.797	2.39	0.22
CDR GV F	1	–0.082	0.082	3.00	0.797	2.39	0.20
CLIFTN B	230	–0.080	0.080	2.55	0.797	2.03	0.16
CLIFTN K	230	–0.079	0.079	2.55	0.797	2.03	0.16
JACKSON	1	–0.078	0.078	9.70	0.797	7.73	0.60
SADDLBRK	230	–0.076	0.076	–0.40	0.797	–0.32	–0.02
COOKRD C	230	–0.075	0.075	3.70	0.797	2.95	0.22
ATHENIA 1	138	–0.074	0.074	13.70	0.781	10.70	0.79
EST RUTH	138	–0.074	0.074	15.60	0.757	11.81	0.87
HINCH.AV	230	–0.074	0.074	14.60	0.797	11.64	0.86
MAYWOOD	230	–0.074	0.074	26.90	0.797	21.44	1.59
BELLVLLE	230	–0.073	0.073	5.80	0.741	4.30	0.31
KINGLND	1	–0.072	0.072	3.05	0.797	2.43	0.18
N.MILFRD	230	–0.072	0.072	12.10	0.797	9.64	0.69
KULLR RD	138	–0.071	0.071	4.10	0.797	3.27	0.23
ATHENIA3	138	–0.071	0.071	13.70	0.781	10.70	0.76
FAIRLAWN	138	–0.070	0.070	8.10	0.761	6.16	0.43
HILLSDLE	230	–0.070	0.070	2.90	0.797	2.31	0.16
LEONIA T	230	–0.070	0.070	29.00	0.797	23.11	1.62
NJT MDW	230	–0.069	0.069	6.40	0.797	5.10	0.35
PENHRN Y	230	–0.068	0.068	13.20	0.797	10.52	0.72
W.CALD G	138	–0.068	0.068	10.80	0.797	8.61	0.59
BERGEN	230	–0.068	0.068	17.90	0.717	12.83	0.87
HAWTHORN	230	–0.068	0.068	5.80	0.797	4.62	0.31
BERGEN	138	–0.067	0.067	65.60	0.717	47.04	3.15
PENHRN X	230	–0.067	0.067	13.20	0.797	10.52	0.70
N.BERGN	1	–0.067	0.067	8.55	0.797	6.81	0.46
KINGLND	1	–0.067	0.067	3.05	0.797	2.43	0.16
NEWPORT2	230	–0.067	0.067	74.20	0.797	59.14	3.96
N.BERGN	1	–0.067	0.067	8.55	0.797	6.81	0.46
HOBOKEN	1	–0.067	0.067	18.70	0.797	14.90	1.00
HOMSTD E	138	–0.067	0.067	15.60	0.797	12.43	0.83
MARION 1	138	–0.066	0.066	11.70	0.781	9.14	0.60
TURNPK G	138	–0.066	0.066	3.10	0.797	2.47	0.16
LRL,MD T	138	–0.065	0.065	12.45	0.797	9.92	0.64

Illustration of PSE&G Method for Determining a Transmission Project's Cost Per Kilowatt of Contributing Load Growth Upgrade of Branchburg–Bridgewater 230–kV Circuit Project

Bus Name		Generation DFAX (1)	Load DFAX −(1) (2)	1992–2002 Station Load Growth (MW) (3)	Substation To System Coincidence Factor (4)	Coincident Substation Load Growth (MW) (3) x (4) (5)	Contribution To Branchburg–Bridgewater Line Flow (MW) (2) x (5) (6)
JERSEY C	1	−0.064	0.064	3.80	0.757	2.88	0.18
HOMSTD F	138	−0.064	0.064	3.70	0.797	2.95	0.19
WALDWICK	230	−0.063	0.063	11.00	0.797	8.77	0.55
COOKRD D	138	−0.062	0.062	3.90	0.797	3.11	0.19
TURNPK D	138	−0.062	0.062	3.10	0.797	2.47	0.15
W.CALD D	138	−0.062	0.062	10.50	0.797	8.37	0.52
W.ORANGE	138	−0.062	0.062	15.60	0.757	11.81	0.73
LRL,MD S	138	−0.062	0.062	12.45	0.797	9.92	0.62
MARION 3	138	−0.062	0.062	11.70	0.781	9.14	0.57
BAYONNE	138	−0.060	0.060	20.20	0.733	14.81	0.89
ESSEX	26	−0.060	0.060	13.35	0.761	10.16	0.61
ESSEX	13	−0.060	0.060	3.40	0.781	2.66	0.16
SPRINGRD	138	−0.058	0.058	8.30	0.797	6.62	0.38
FOUNDRY	138	−0.058	0.058	6.60	0.797	5.26	0.31
NEWARK	138	−0.058	0.058	88.20	0.781	68.88	4.00
PVSC	138	−0.058	0.058	1.50	0.797	1.20	0.07
NORTH AV	138	−0.056	0.056	12.80	0.797	10.20	0.57
DORM PL	138	−0.055	0.055	5.50	0.797	4.38	0.24
LINDEN 3	138	−0.053	0.053	9.75	0.765	7.46	0.40
BAYWY1−4	138	−0.052	0.052	3.53	0.749	2.64	0.14
LINDEN 1	138	−0.052	0.052	9.75	0.765	7.46	0.39
BAYWY5−7	138	−0.050	0.050	3.53	0.749	2.64	0.13
FANWOOD	1	−0.038	0.038	3.70	0.797	2.95	0.11
NEWDOVR	1	−0.031	0.031	5.70	0.797	4.54	0.14
WARINANC	230	−0.023	0.023	4.40	0.797	3.51	0.08
MINUEST	1	−0.022	0.022	2.20	0.797	1.75	0.04
ALDENE	230	−0.021	0.021	−2.50	0.717	−1.79	−0.04
MINUEST	1	−0.021	0.021	2.20	0.797	1.75	0.04
LUMBRTN	230	−0.020	0.020	24.20	0.797	19.29	0.39
SEWAREN	230	−0.018	0.018	19.40	0.797	15.46	0.28
NEWDOVR	1	−0.016	0.016	5.70	0.797	4.54	0.07
CLARKSVL	230	−0.016	0.016	22.20	0.797	17.69	0.28
SEWAREN	138	−0.015	0.015	10.60	0.717	7.60	0.11
LAWRENCE	230	−0.014	0.014	109.85	0.751	82.50	1.15
LAF,WBD	1	−0.014	0.014	9.10	0.797	7.25	0.10
PIER AV	1	−0.013	0.013	6.10	0.797	4.86	0.06
PIER AV	1	−0.012	0.012	6.10	0.797	4.86	0.06
METUCHN1	138	−0.012	0.012	11.80	0.725	8.56	0.10
MDW RD Q	138	−0.011	0.011	7.60	0.797	6.06	0.07
MT. LRL	1	−0.011	0.011	19.80	0.797	15.78	0.17
MARLTON2	230	−0.011	0.011	29.20	0.797	23.27	0.26
MT. LRL	1	−0.011	0.011	19.80	0.797	15.78	0.17
KUSER A	230	−0.011	0.011	11.70	0.797	9.32	0.10
MARLTON1	230	−0.011	0.011	16.80	0.797	13.39	0.15

Table 2
Page 3 of 3

Illustration of PSE&G Method for Determining a Transmission Project's Cost Per Kilowatt of Contributing Load Growth Upgrade of Branchburg–Bridgewater 230–kV Circuit Project

Bus Name		Generation DFAX	Load DFAX	1992–2002 Station Load Growth (MW)	Substation To System Coincidence Factor	Coincident Substation Load Growth (MW)	Contribution To Branchburg–Bridgewater Line Flow (MW)
			–(1)			(3) x (4)	(2) x (5)
		(1)	(2)	(3)	(4)	(5)	(6)
LAF, WBD	1	–0.009	0.009	9.10	0.797	7.25	0.07
KUSER H	230	–0.009	0.009	11.30	0.797	9.01	0.08
PLAINSBR	138	–0.008	0.008	38.20	0.797	30.45	0.24
TRENTON	138	–0.005	0.005	26.55	0.709	18.82	0.09
COLONIAL	138	–0.004	0.004	1.10	0.797	0.88	0.00
CROSWK Z	138	–0.004	0.004	12.65	0.797	10.08	0.04
CROSWK Y	138	–0.004	0.004	12.65	0.797	10.08	0.04
METUCHN 3	138	–0.003	0.003	11.80	0.725	8.56	0.03
BEAVR BK	230	–0.003	0.003	15.60	0.797	12.43	0.04
DEPTFORD	230	–0.002	0.002	9.70	0.797	7.73	0.02
BSTLTN Y	138	–0.002	0.002	5.60	0.757	4.24	0.01
BSTLTN Z	138	–0.002	0.002	5.60	0.757	4.24	0.01
GLOUCSTR	230	–0.002	0.002	14.80	0.755	11.17	0.02
BURLINGT	7	–0.001	0.001	4.00	0.725	2.90	0.00
THOROFAR	1	–0.001	0.001	12.70	0.797	10.12	0.01
MDW RD R	138	–0.001	0.001	7.60	0.797	6.06	0.01
LEVITN I	138	0.000	0.000	8.70	0.797	6.93	0.00
CUTHBERT	138	0.001	–0.001	14.50	0.797	11.56	–0.01
CINN I	138	0.001	–0.001	9.30	0.797	7.41	–0.01
HOEGANES	13	0.001	–0.001	–3.20	0.797	–2.55	0.00
LEVINTN J	138	0.001	–0.001	11.80	0.797	9.40	–0.01
CAMDEN	138	0.001	–0.001	16.00	0.725	11.60	–0.01
CINN J	138	0.001	–0.001	9.30	0.797	7.41	–0.01
DEYFOR N	138	0.002	–0.002	51.70	0.797	41.20	–0.08
CAMDEN	230	0.003	–0.003	14.80	0.773	11.44	–0.03
BRUNSWCK	138	0.008	–0.008	18.01	0.717	12.91	–0.10
BRUNSWCK	230	0.025	–0.025	53.10	0.793	42.11	–1.05
ADAMBN X	230	0.035	–0.035	15.60	0.797	12.43	–0.44
SUNNYM Y	230	0.100	–0.100	6.35	0.797	5.06	–0.51
TOTAL						1233.61	68.28

RESULTS

(A) Branchburg–Bridgewater Circuit Upgrade Capital Expenditure (1994 $000):	$6,200
(B) Ten–Year Added Flow on B–B Circuit (MW):	68.28
(C) Average Cost per kW of Contributing Coincident Load Growth (1994 Dollars) (A) / (B)	$90.80

Source: Based on exhibits in Robert Stack, "An Area–Specific Transmission Marginal Costing Methodology," PSE&G, presented at the NERA Marginal Cost Working Group meeting in Portland, Maine, October 1993.

Illustration of PSE&G's Method for Determining Marginal Area Transmission Investment Associated With a Particular Project Upgrade of Branchburg–Bridgewater 230–kV Circuit

Bus Name		Coincident Substation Load Growth (MW)	Contribution to Branchburg–Bridgewater Line Flow (MW)	Load Weighted Area Load DFAX	Area Marginal Investment (due to B–B project) (1994$ / kW of Load Growth at Substation)
				(2) / (1)	(3) x $90.80 [1]
		(1)	(2)	(3)	(4)
SUNNYM C	230	5.06	3.78		
SOMRVLLE	230	19.21	11.76		
BRIDGWTR	230	−0.65	−0.35		
L.NELSN	1	6.62	2.44		
GREENBK	1	3.03	1.05		
KILMER I	230	17.53	5.98		
KILMER W	230	9.48	2.18		
L.NELSN	1	6.62	1.48		
GREENBK	1	3.03	0.64		
SUBTOTAL		69.92	28.94	0.414	$37.58
BRUNSWCK	138	12.91	−0.10		
BRUNSWCK	230	42.11	−1.05		
ADAMBN X	230	12.43	−0.44		
SUNNYM Y	230	5.06	−0.51		
SUBTOTAL		72.51	−2.09	−0.029	($2.62)
CDR GV B	230	2.39	0.22		
CDR GV F	1	2.39	0.20		
CLIFTN B	230	2.03	0.16		
CLIFTN K	230	2.03	0.16		
JACKSON	1	7.73	0.60		
SADDLBRK	230	−0.32	−0.02		
COOKRD C	230	2.95	0.22		
ATHENIA 1	138	10.70	0.79		
EST RUTH	138	11.81	0.87		
HINCH.AV	230	11.64	0.86		
MAYWOOD	230	21.44	1.59		
BELLVLLE	230	4.30	0.31		
KINGLND	1	2.43	0.18		
N.MILFRD	230	9.64	0.69		
ATHENIA3	138	10.70	0.76		
KULLR RD	138	3.27	0.23		
HILLSDLE	230	2.31	0.16		
LEONIA T	230	23.11	1.62		
FAIRLAWN	138	6.16	0.43		
NJT MDW	230	5.10	0.35		
HAWTHORN	230	4.62	0.31		

Illustration of PSE&G's Method for Determining Marginal Area Transmission Investment Associated With a Particular Project Upgrade of Branchburg–Bridgewater 230–kV Circuit

Bus Name		Coincident Substation Load Growth	Contribution to Branchburg–Bridgewater Line Flow	Load Weighted Area Load DFAX	Area Marginal Investment (due to B–B project)
		------ (MW) ------			(1994$ / kW of Load Growth at Substation)
				(2) / (1)	(3) x $90.80 [1]
		(1)	(2)	(3)	(4)
PENHRN Y	230	10.52	0.72		
BERGEN	230	12.83	0.87		
W.CALD G	138	8.61	0.59		
HOBOKEN	1	14.90	1.00		
HOMSTD E	138	12.43	0.83		
PENHRN X	230	10.52	0.70		
N.BERGN	1	6.81	0.46		
N.BERGN	1	6.81	0.46		
BERGEN	138	47.04	3.15		
KINGLND	1	2.43	0.16		
NEWPORT2	230	59.14	3.96		
MARION 1	138	9.14	0.60		
TURNPK G	138	2.47	0.16		
LRL,MD T	138	9.92	0.64		
HOMSTD F	138	2.95	0.19		
JERSEY C	1	2.88	0.18		
WALDWICK	230	8.77	0.55		
W.CALD D	138	8.37	0.52		
TURNPK D	138	2.47	0.15		
COOKRD D	138	3.11	0.19		
MARION 3	138	9.14	0.57		
LRL,MD S	138	9.92	0.62		
W.ORANGE	138	11.81	0.73		
SUBTOTAL		419.44	28.71	0.068	$6.22
BAYONNE	138	14.81	0.89		
ESSEX	13	2.66	0.16		
ESSEX	26	10.16	0.61		
SPRINGRD	138	6.62	0.38		
FOUNDRY	138	5.26	0.31		
NEWARK	138	68.88	4.00		
PVSC	138	1.20	0.07		
NORTH AV	138	10.20	0.57		
DORM PL	138	4.38	0.24		
LINDEN 3	138	7.46	0.40		
BAYWY1–4	138	2.64	0.14		
LINDEN 1	138	7.46	0.39		
BAYWY5–7	138	2.64	0.13		
FANWOOD	1	2.95	0.11		

Illustration of PSE&G's Method for Determining Marginal Area Transmission Investment Associated With a Particular Project Upgrade of Branchburg–Bridgewater 230–kV Circuit

Bus Name		Coincident Substation Load Growth (MW)	Contribution to Branchburg–Bridgewater Line Flow (MW)	Load Weighted Area Load DFAX	Area Marginal Investment (due to B–B project) (1994$ / kW of Load Growth at Substation)
		(1)	(2)	(2) / (1) (3)	(3) x $90.80 [1] (4)
NEWDOVR	1	4.54	0.14		
ALDENE	230	−1.79	−0.04		
WARINANC	230	3.51	0.08		
SUBTOTAL		153.57	8.57	0.056	$5.07
MINUEST	1	1.75	0.04		
MINUEST	1	1.75	0.04		
SEWAREN	230	15.46	0.28		
CLARKSVL	230	17.69	0.28		
NEWDOVR	1	4.54	0.07		
SEWAREN	138	7.60	0.11		
LAF,WBD	1	7.25	0.10		
LAF,WBD	1	7.25	0.07		
MDW RD Q	138	6.06	0.07		
MDW RD R	138	6.06	0.01		
PIER AV	1	4.86	0.06		
PIER AV	1	4.86	0.06		
METUCHN1	138	8.56	0.10		
METUCHN3	138	8.56	0.03		
SUBTOTAL		102.26	1.31	0.013	$1.17
MT. LRL	1	15.78	0.17		
KUSER A	230	9.32	0.10		
MT. LRL	1	15.78	0.17		
MARLTON2	230	23.27	0.26		
MARLTON1	230	13.39	0.15		
KUSER H	230	9.01	0.08		
PLAINSBR	138	30.45	0.24		
LAWRENCE	230	82.50	1.15		
TRENTON	138	18.82	0.09		
COLONIAL	138	0.88	0.00		
CROSWK Y	138	10.08	0.04		
CROSWK Z	138	10.08	0.04		
BEAVR BK	230	12.43	0.04		
LUMBRTN	230	19.29	0.39		
DEPTFORD	230	7.73	0.02		
GLOUCSTR	230	11.17	0.02		
BSTLTN Y	138	4.24	0.01		
BSTLTN Z	138	4.24	0.01		

Illustration of PSE&G's Method for Determining Marginal Area Transmission Investment Associated With a Particular Project Upgrade of Branchburg–Bridgewater 230–kV Circuit

Bus Name		Coincident Substation Load Growth	Contribution to Branchburg–Bridgewater Line Flow	Load Weighted Area Load DFAX	Area Marginal Investment (due to B–B project)
		------ (MW) ------			(1994$ / kW of Load Growth at Substation)
				(2) / (1)	(3) x $90.80 [1]
		(1)	(2)	(3)	(4)
THOROFAR	1	10.12	0.01		
BURLINGT	7	2.90	0.00		
SUBTOTAL		311.49	3.00	0.010	$0.88
LEVITN I	138	6.93	0.00		
LEVITN J	138	9.40	−0.01		
CAMDEN	138	11.60	−0.01		
CINN J	138	7.41	−0.01		
CINN I	138	7.41	−0.01		
CUTHBERT	138	11.56	−0.01		
HOEGANES	138	−2.55	0.00		
DEYFOR N	138	41.20	−0.08		
CAMDEN	230	11.44	−0.03		
SUBTOTAL		104.41	−0.16	−0.002	($0.14)

[1] From Table 2, page 3, Results, line (C).

Source: Based on exhibits in Robert Stack, "An Area–Specific Transmission Marginal Costing Methodology," PSE&G, presented at the NERA Marginal Cost Working Group meeting in Portland, Maine, October 1993. See also Table 2.

Table 4

Illustration of CMP's Marginal Transmission Cost Analysis Using Area Studies
Bath / Brunswick Area

Project	Cost (1992$)	Designation	Growth at 1 Percent: Year Needed	Growth at 1 Percent: Cost at In–service Date [1] (Dollars)	Growth at 1 Percent: 1993 Present Value [2] (1993$)	Growth at 3 Percent: Year Needed	Growth at 3 Percent: Cost at In–service Date [1] (Dollars)	Growth at 3 Percent: 1993 Present Value [2] (1993$)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Sect. 77 Sectionalizing	$125,000	G	1992	$125,000	$138,750	1992	$125,000	$138,750
Rebuild S11 & Bath Caps	540,000	L	1992	540,000	599,400	1992	540,000	599,400
Upgrade Section 31 & 55	99,000	S	1992	99,000	109,890	1992	99,000	109,890
Replace Sect. 77 Cable	60,000	G	1998	71,643	42,517	1993	61,800	61,800
Second Bath 115/34 kV	2,400,000	G	2002	3,225,399	1,260,888	1995	2,622,545	2,128,516
Sum of Growth–Related (G) Project Present Value Costs					$1,442,155			$2,866,666

	1% Growth (9)	3% Growth (10)	Difference Between 1% and 3% Growth (10)–(9) (11)
(A) 10–Year Load Growth (MW)	12.50	41.25	28.75
(B) 1993 Present Value of Growth–Related Projects (Dollars)	$1,442,155	$2,866,666	$1,424,511
(C) Area Marginal Costs (1993 Present Value of Investment per kW) (B) / (A)	$115.37	$69.49	$49.55

[1] Based on an inflation rate of 3 percent.
[2] Based on a discount rate of 11 percent.

Source: Based on Prefiled Direct Testimony of Waine Whittier in Maine Public Utilities Commisison Docket 92–315, filed February 17, 1993.

Information Request TEC-3-32

Please provide a copy of "Standby Rates for Cogenerators and Small Power Producers" (November 15, 1985).

Response

A copy is provided as Attachment TEC-3-32.

ILLINOIS POWER COMPANY
STANDBY ELECTRIC RATES FOR
COGENERATORS AND SMALL POWER PRODUCERS

Prepared by

National Economic Research Associates, Inc.

November 1, 1985

n/e/r/a

ILLINOIS POWER COMPANY
STANDBY ELECTRIC RATES FOR COGENERATORS AND SMALL POWER PRODUCERS

CONTENTS

ILLINOIS POWER COMPANY
STANDBY ELECTRIC RATES FOR
COGENERATORS AND SMALL POWER PRODUCERS

EXHIBITS AND APPENDICES

ILLINOIS POWER COMPANY
STANDBY ELECTRIC RATES FOR
COGENERATORS AND SMALL POWER PRODUCERS

EXECUTIVE SUMMARY

I. INTRODUCTION

By federal and state law, Illinois Power Company (IP) is required to provide supplemental, backup, maintenance, and interruptible service to qualifying cogenerators and small power producers on its system. Supplemental power serves on a regular basis the loads that exceed the generation capability of the facility. Backup and maintenance service provide temporary power when the facility is inoperative on an unplanned or planned basis, respectively. Interruptible power is not a firm commitment on the utility's part, but service which can be curtailed or halted under specified conditions.

The purpose of this report is to review IP's statutory obligations to sell electricity to qualifying facilities, to discuss the characteristics of appropriate rates charged to qualifying facilities, to recommend a method for setting those rates, and to provide a sample rate sheet.

II. STATUTORY OBLIGATIONS

Under the Public Utility Regulatory Policies Act of 1978 (PURPA), utilities are required to sell electric energy to qualifying facilities. The rates charged must be just, reasonable, in the public interest and not discriminate against qualifying facilities. The Federal Energy Regulatory Commission (FERC) regulations implementing this section of PURPA specify the four types of service which must be offered: supplemental, backup, maintenance and interruptible. The FERC regulations also provide more detailed instructions on how rates for these services are to be designed. Rates are not considered discriminatory if they are based on accurate data and consistent systemwide costing principles applicable to other customers with similar load or other cost-related characteristics. Maintenance and backup rates must not be based on the assumption that all qualifying facilities will need these services simultaneously or at the time of the system peak and must take into consideration the degree to which maintenance is scheduled during periods advantageous to the utility.

The Illinois state regulations (both in General Order 214 and the new Illinois Public Utilities Act) reiterate the provisions that rates charged to qualifying facilities must be just, reasonable, in the public interest and non-discriminatory. Charges must be at the utility's regular rates unless the loads or other cost characteristics of the qualifying facilities justify different charges. If different charges are developed, customers who are not qualifying facilities but have similar loads must be allowed to take service under those charges. All special rates must be approved by the Commission, but separate contracts can be negotiated.

III. SUPPLEMENTAL SERVICE

Supplemental service is taken on a regular basis because the qualifying facility's electrical output is insufficient to meet its full electrical requirements. For most qualifying facilities, the load characteristics of supplemental service will be similar to loads of nongenerating customers. Therefore, we recommend that supplemental service be provided under the regular IP rate schedule for which the qualifying facility is eligible, given the characteristics of its supplemental load. If it turns out that supplemental service for some qualifying facilities is very intermittent in nature, it may be appropriate to specify new eligibility requirements for the regular rates, and charge customers not meeting those requirements (whether they are qualifying facilities or not) under the standby rate.

IV. INTERRUPTIBLE SERVICE

If qualifying facilities take supplemental service under the large power rate, Service Classification 21 (S.C. 21), they will be eligible for Rider S for interruptible service. This provision will fulfill IP's obligation to offer interruptible service to qualifying facilities.

V. STANDBY SERVICE

We refer jointly to maintenance and backup service as standby service. Since loads under both types of service will be intermittent, it is appropriate to charge for both under the same rate schedule.

Appropriate standby rates have the following characteristics:

1. A nondiscriminatory cost basis. Since IP's regular rates are based on marginal costs, standby rates should be too.

2. Time-differentiation. The intermittent nature of standby service makes it especially important to charge for the service based on time of use.

3. Required Facilities. The first level of the system used by a standby customer (for example the subtransmission system for a customer served at subtransmission voltage) must be sized to handle the customer's maximum expected load, even if no standby service is ever used. To compensate the utility for having these facilities in place, a monthly "required facilities" charge to be paid regardless of usage is necessary.

4. Voltage Differentiation. If qualifying facilities take service at different voltages, the standby rates should reflect the cost differences, to the extent that IP's regular rates do.

5. Degree of Firmness. If standby service is offered on an interruptible basis, the charges should reflect cost savings to IP.

6. Rate Switching. Eligibility for interruptible options should be designed so that customers cannot switch rates to take advantage of temporary situations, in which interruptions are unlikely, if the interruptible rates are based on a longer-term capacity outlook.

7. Customer Diversity. The standby rates should recognize the degree to which standby loads are likely to be imposed simultaneously and the times when capacity is likely to be strained.

We recommend that IP offer a single standby rate based on the S.C. 21 rate. Because there is no experience on which to base a marginal cost study of standby loads, it is not now possible to develop a rate for standby service using the methodology employed for other classes of service. However, a reasonable assumption is that standby customers taking service in a given month will impose capacity costs that vary depending upon the standby customer's on-peak load factor for the month. A standby customer having an on-peak load factor that is only one-half of the S.C. 21 class on-peak load factor is less likely to be using the system at the time of the monthly peak than a typical S.C. 21 customer. Thus, a discount from the S.C. 21 rate, based on the customer's relative on-peak load factor, is a reasonable basis for a stand-by demand charge.

Our specific recommendations for the design of the standby rate (for a subtransmission customer) based on the S.C. 21 rate are as follows:

1. Charge the normal customer (facilities) charge which covers the costs of metering equipment, billing and other administrative costs (unless these costs are already being recovered in the charges for supplemental service).

2. Charge the normal time-differentiated energy charges, adjusted for the $0.0025 per kilowatt-hour adder that was moved from summer demand charges for bill stability reasons and because of the characteristics of the S.C. 21 customer loads.

3. Institute a "required facilities" charge which recovers on a monthly basis, regardless of usage, the annual marginal cost of subtransmission facilities (primary facilities for a primary customer) needed to cover the customer's standby capacity. The marginal costs would be adjusted by the same ratio that marginal demand revenues for the S.C. 21 class were adjusted in setting the S.C. 21 rate.

4. Adjust the S.C. 21 demand charge as follows: remove the effect of the winter ratchet because standby customers will have intermittent loads and may not be using power in all months; put back onto summer demand charges the effect of the $.0025 per kilowatt-hour revenue shift; adjust the winter demand charge to account for the discount to be given for scheduling maintenance in low-cost months; and remove the subtransmission (or primary) component because these costs are being collected in the required facilities charge.

5. Apply to the adjusted S.C. 21 demand charge a load factor adjustment equal to the ratio of the customer's on-peak load factor for the month to the S.C. 21 class on-peak load factor.

6. Give a 50-percent discount on the demand charge for maintenance power used in the two low-cost winter months designated by IP.

These recommendations have been converted into a sample rate sheet which is included as Exhibit A.

VI. CONCLUSIONS

The recommended rates comply with IP's statutory obligations, are feasible to implement, and recognize that to date there is very little information about the characteristics of the loads likely to be imposed by qualifying facilities. By providing a standard standby rate based on the load characteristics of the S.C. 21 class with an adjustment to demand charges for qualifying facilities with on-peak load factors different from the S.C. 21 class average, IP will be offering nondiscriminatory rates while gathering the information on standby load characteristics IP needs to prepare more rigorous cost studies of standby service.

ILLINOIS POWER COMPANY
STANDBY ELECTRIC RATES FOR
COGENERATORS AND SMALL POWER PRODUCERS

I. INTRODUCTION

By federal and state law, Illinois Power Company (IP) is required to provide supplemental, backup, maintenance, and interruptible service to qualifying cogenerators and small power producers on its system. Supplemental power serves on a regular basis the loads that exceed the generation capability of the facility. Backup and maintenance service provide temporary power when the facility is inoperative on an unplanned or planned basis, respectively. Interruptible power is not a firm commitment on the utility's part, but service which can be curtailed or halted under specified conditions.

The purpose of this report is to review IP's statutory obligations to sell electricity to qualifying facilities, to discuss the characteristics of appropriate rates charged to qualifying facilities, to recommend a method for setting those rates, and to provide a sample rate sheet.

II. STATUTORY OBLIGATIONS

Section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA) requires the Federal Energy Regulatory Commission (FERC) to prescribe rules which require electric utilities to sell electric energy to qualifying cogenerators and small power producers.[1] PURPA stated that the rates utilities charged qualifying facilities "(1) shall be just and reasonable and in the public

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1 The definition of qualifying facility, largely a matter of the vintage of the project and the technology used, was set by FERC.

interest, and (2) shall not discriminate against the qualifying cogenerators or qualifying small power producers."[2]

The FERC regulations implementing PURPA Section 210 provide guidance on the meaning of discrimination with respect to qualifying facilities: "Rates for sales which are based on accurate data and consistent systemwide costing principles shall not be considered to discriminate against any qualifying facility to the extent that such rates apply to the utility's other customers with similar load or other cost-related characteristics."[3] The FERC regulations also require that rates for sales of maintenance and backup power must not be based on the assumption that all qualifying facilities will need these services simultaneously or at the time of the system peak (unless supported by factual data) and must take into account the degree to which maintenance is scheduled during periods advantageous to the utility.[4]

The State of Illinois has imposed obligations on IP similar to the federal regulations. According to General Order 214:

> k) (1) The utility shall offer to provide maintenance, supplemental and [backup][5] power to the qualifying facility. The utility shall offer to provide interruptible power if a standard rate schedule for interruptible power has been approved by the Commission. Charges for interruptible power, maintenance power, [backup] power and supplemental power imposed on the qualifying facility for electricity or reserve capability furnished by the utility shall be at the utility's standard rates, unless the load or other cost characteristics related to the provision

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2 PURPA, Section 210(c).

3 FERC Order 69, 18 CFR Part 292.305(a)(2).

4 Ibid., Part 202.305(c).

5 General Order 214 uses the term standby instead of backup. However, we have used the term backup to be consistent with the federal terminology. We use the term standby to refer to both backup and maintenance service.

> of such services justifies different charges. Any such different charges for the provision of such services must be approved by the Commission and shall be applicable to all jurisdictional customers without regard to whether or not they operate qualified facilities hereunder.
>
> (2) Nothing in this subsection (k) shall limit the authority of a utility and qualifying facility to agree to any rate or terms or conditions relating to the provision of interruptible, maintenance, [backup],[6] and supplemental power.[7]

III. SUPPLEMENTAL SERVICE

No special rates for supplemental service are generally necessary. The degree to which the qualifying facility needs to rely on the utility to supply the electricity it cannot provide with its own generation equipment can be determined. The customer can then be assigned to the regular customer class appropriate for a customer of this size and characteristics. In the event that supplemental loads of some customers are very intermittent, it may be necessary to charge for their supplemental use under the standby rate.

IV. CHARACTERISTICS OF APPROPRIATE STANDBY RATES

In addition to the requirements imposed by federal and state regulations, there are technical, economic and equity factors which dictate the characteristics of appropriate standby rates. In the paragraphs below we will examine these important characteristics.

A. Nondiscrimination

It is clear from the federal and state regulations that rates for qualifying facilities can differ from rates charged to customers in the class to

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6 See footnote 5.

7 Illinois Administrative Code, Title 83: Chapter I: Subchapter c: Part 430.

which the qualifying facilities would otherwise belong only to the extent that those differences can be cost justified. The extreme uncertainty associated with needs for maintenance and backup service and the intermittent nature of the service suggest that there are distinct differences between the costs of serving regular customers and the costs of serving customers with their own generating facilities. The key to development of appropriate rates for qualifying facilities is to quantify those cost differences.

Rates charged qualifying facilities will be nondiscriminatory if they bear the same relationship to the cost of serving these customers that the rates for regular customers bear to the costs of supplying their electrical needs. For example, if rates for industrial customers are below marginal cost, then rates for qualifying facilities should be below marginal cost to the same degree. By the same token, if industrial rates are above short-run marginal costs because the utility has just added new capacity and has ample reserves but a high revenue requirement, unless there is some other cost justification it would be discriminatory to charge qualifying facilities only short-run marginal costs without asking them to pick up their share of the added revenue requirement.

B. Time-Differentiation

The most efficient and equitable way to price standby service is to develop rates which vary by season and time of day. While regular industrial customers have loads which are normally very consistent across time, or at least fairly predictable to the extent that they do vary, standby service is highly unpredictable and erratic. A qualifying facility which uses standby power only in the off-peak hours imposes very different costs on the utility from those imposed by a facility which needs its maximum standby deliveries at the time of the system peak.

To take into consideration a qualifying facility's willingness to schedule its maintenance at a time that is most useful for the utility, it may be appropriate to provide even more seasonal differentiation in standby rates than in regular industrial rates. For example, IP's industrial rates are differentiated into two seasons, a four-month summer period and an eight-month winter period. However, within those major periods there may be a month or two in which IP's reserve margins are greatest. By splitting the year into more than two seasonal periods, the charges for maintenance power would reflect the benefits to IP from coordinated scheduling of maintenance and would give the qualifying facilities the incentive to coordinate.

There may be small customers for whom time-of-use metering is not cost effective. Alternative, nontime-differentiated standby rates would have to be developed for these customers, based on estimates (and historical experience, as it is gained) of the time patterns of their use of standby service.

C. Required Facilities

Even if a qualifying facility never uses standby service, the utility must maintain facilities to make possible the service should the need arise for it. Metering equipment clearly must be in place to determine whether or not service was taken. Certain other facilities will be required to connect the customer to the utility system and will vary depending on the size of the customer and the voltage level at which it takes service. Distribution, transmission and generation capacity will also probably be required to provide reliable standby service.

D. Voltage Differentiation

The facilities used and losses incurred to supply a given customer depend upon the voltage level of service. A qualifying facility served at transmission level voltage is less costly to serve than a customer taking service at subtransmission or primary voltage, all else being equal. To the extent that the utility's regular customers are charged on the basis of voltage level of delivery, standby rates should be similarly differentiated.

E. Degree of Firmness

A qualifying facility willing to accept interruptible standby service generally imposes fewer costs on the utility than one which needs firm service. (The exception would be the case where the utility's situation was such that it did not need to interrupt standby service in order to avoid capacity additions or to reduce energy costs.) To the extent that interruptible service is provided to regular customers, the Illinois regulations require that interruptible service be provided to qualifying facilities as well. Discounts based on the same principles used to develop the regular interruptible riders should be used to set interruptible rates for qualifying facilities.

IP does have standard interruptible riders to its industrial rates. Therefore, under the terms of General Order 214, the company is obligated to offer interruptible service to qualifying facilities as well.

F. Priority of Service

Any interruptible rate offered to qualifying facilities should make clear to these customers where their loads stand in relation to other loads. Who is interrupted first when a condition triggering the need for curtailments is encountered?

G. Rate Switching

A utility offering interruptible service in a time when interruptions are rare may find that the service is very popular until the need for more frequent interruptions occurs. Eligibility requirements and terms of service should be designed so that customers do not take advantage of discounts in interruptible rates based on the long-run benefits of having a portion of the utility's load controllable, but switch to firm rates when interruptions become likely. This cautionary note applies to regular as well as qualifying facility interruptible rates.

H. Customer Diversity

The cost of supplying standby service will vary as the diversity of customers seeking that service increases. For example, the utility is more likely to have to add generation and transmission capacity to provide standby service to a single new 100-megawatt standby customer than to 10 10-megawatt customers. The chances of having to supply 100 megawatts of standby power at a time when the system is strained is much more likely in the first case than in the second. Standby charges should take this degree of diversity into consideration. However, it is not simply the number or size of customers which affects diversity. If all standby customers are in the same industry, all use the same fuel, and all have the same type of cogeneration equipment, the fact that there are ten of them instead of one may not have a tremendous effect on the diversity of their standby needs. (Of course the forced outages, which would tend to occur randomly, would be spread out more in the case of more customers.)

I. Power Factor Adjustment

As in rates for other large customers, it is important to include in the rates for standby customers a requirement to maintain power factor within acceptable limits. A poor power factor imposes costs on the utility which must be paid for by the customer causing them to be incurred, or spread to other customers.

V. COSTS OF STANDBY SERVICE

There are three types of costs incurred in providing standby service to qualifying facilities. These are customer costs, energy costs and capacity costs (distribution, subtransmission, transmission and generation). Each of these costs is properly evaluated at the margin. In addition there may be short-run financial losses imposed on the utility and its regular ratepayers because standby customers are no longer taking full electrical service.

A. Customer Costs

Even if a standby customer rarely takes service, the utility must install and maintain metering equipment as well as incur administrative costs associated with metering reading, billing, customer service and customer information. For customers served at distribution voltage, there is also the cost of minimum distribution facilities necessary to connect the customer to the utility system. Each of these costs is the responsibility of the standby customer.

B. Energy Costs

When a standby customer takes service, the utility incurs marginal energy costs, including incremental energy losses, for each kilowatt-hour actually used. These costs vary depending on the time the energy is taken, and on the voltage level of delivery.

C. Capacity Costs

The amount of distribution, subtransmission, transmission and generation capacity a utility must install and maintain to provide standby service depends on the voltage level of service, the pattern of firm load on various parts of the system, the maximum potential demands by standby customers, and the timing of those demands. If the utility could predict the patterns of demands by its standby customers, it could develop precise estimates of the added generation, transmission and distribution reserves needed to maintain reliable service for all customers. The probabilistic nature of the standby loads would just be an additional element of uncertainty in a planning process which has to deal with customer loads and capacity availability which are not known with certainty. For example, just as the utility has to provide extra capacity to allow for the possibility that some of its generating units will be unavailable at any given time, the addition of uncertain standby loads will increase reserve requirements. Granted, the utility has years of experience predicting load fluctuations, generator forced outage rates, transmission and distribution equipment failure rates, etc. Most utilities have little or no idea what the demands of their potential standby customers will be.

The capacity cost of providing standby service is a function of the probabilities that demands will occur at times when there is inadequate capacity to supply them. If the load factor of customer loads on a given portion of the utility system is high, the addition of random standby loads is more likely to require capacity additions than would be the case if existing customers' loads had a low load factor. In the second case there would be many hours when the existing capacity would be adequate to handle the added standby loads.

1. Distribution Costs

Most cogenerators are connected to the utility system at sub-transmission or transmission voltage. However, in the event that smaller qualifying facilities may request standby service, it is appropriate to mention the distribution costs incurred to supply distribution-level standby service.

There is so little diversity on secondary facilities that IP treats the marginal costs of secondary facilities as being independent of the time period of a customer's use. That is, the facilities have to be sized to handle individual customer's peak loads, no matter when they occur. Similarly, standby customers cause the addition of secondary distribution capacity (provided they take service a secondary voltage) equal to their maximum potential loads, whether they ever take standby service or not.

There is often more diversity at the primary distribution level. Therefore, the additional capacity needed to ensure reliable standby service without denigrating the quality of service to other customers depends on the timing of standby loads and peak demands on the primary facilities.[8] Using a probabilistic analysis, if sufficient data are available, the utility can determine the likelihood that standby loads will coincide with peak demands on the primary system and can maintain enough capacity to keep reliability at an adequate level. The amount of extra capacity needed times the marginal cost of primary distribution capacity is a cost of standby service.

2. Subtransmission Costs

Customers connected to the utility's system at subtransmission voltage often have a substation dedicated to them. If not, their maximum load is generally a key factor in the sizing of the substation that does serve them. For these large customers, there is simply not enough diversity on the local subtransmission system to accommodate their maximum potential load without specifically providing that amount of subtransmission capacity. Standby customers served at subtransmission voltage are thus responsible for the marginal costs of subtransmission capacity adequate to handle their highest potential demand for standby service.

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8 A customer served at primary voltage is likely to contribute a significant portion of the total load on the local primary facilities. Thus, that customer's maximum load will generally play an important role in the sizing of those facilities, much as is the case for secondary customers' loads on secondary facilities.

Distribution level customers use subtransmission facilities, but generally share them with many other customers. Thus the diversity of loads provides a cushion of capacity. It is likely that standby demands by these customers can be accommodated without adding subtransmission capacity equal to the maximum potential demand they could exert on the system. For example, if there is a random pattern of standby demands and a probability that standby service would be required for only five percent of the hours in a year, then the expected standby load at the time of the peak on a portion of the subtransmission system is only 5 percent of the maximum potential standby load. The actual amount of capacity that would have to be maintained for standby service would depend on the utility's reserve criteria for subtransmission facilities.

3. Transmission Costs

Standby customers taking service at transmission voltage may require special equipment to connect them to the transmission grid. The costs of these facilities should be considered customer costs for the specific customer. Unlike service at lower voltages, the main transmission grid is sized to handle the diversified loads of a large number of customers. Transmission capacity necessary to provide standby service will, once again, depend on the probability that standby service will be required at the times when transmission capacity is strained and on the size of those potential standby loads. The best measure of costs incurred to serve standby loads is the time-differentiated marginal cost of transmission capacity times the expected standby load in each costing period.

4. Generation Capacity Costs

The generation capacity costs incurred to serve standby customers can be determined in the same way as transmission capacity costs. The need for capacity to serve standby customers depends on the expected loads of those customers at the times that generation capacity is strained.

D. Utility and Ratepayer Losses

In addition to the three types of costs identified above, there is a fourth element of cost associated with providing standby service. If, by providing standby service, a utility makes it feasible for an existing customer to build and operate generation capacity to supply a portion of its own electrical needs, the utility has lost the revenues it would have used to offset fixed costs incurred to serve that customer. Until loads expand to take up the slack caused by the lost load, the utility's remaining ratepayers (or perhaps stockholders) will have to pick up those fixed costs. Thus, there is a loss associated with supplying backup service that is equal to the difference between the revenue lost and the reduction in costs attributable to the loss of an existing customer. In the case of IP these losses consist of both electric and gas revenues.

In addition to causing losses for the utility and its regular ratepayers, a customer's decision to self generate can have economic costs too. Consider the case where the utility has sufficient capacity to serve the potential cogenerator, but is charging rates that are higher than marginal costs, for whatever reason. A customer may decide to cogenerate because cogenerated power is cheaper than buying from the utility, when in fact from society's point of view it is cheaper to supply the customer's electrical needs with the utility's existing capacity. In this case, allowing the customer to cogenerate is inefficient because it results in an increase in the total cost of electricity supply.

It is not the provision of standby service which is causing the losses to the utility and its ratepayers and the potential sacrifice of efficiency, but the underlying relationship between the utility's marginal costs, the utility's rates and the cost of cogenerated power. Instead of trying to solve the problem with standby rates, a better alternative is to consider the feasibility of designing rates for customers with very elastic demands for electricity (those with the potential to supply their own electrical needs) which make leaving the system less attractive, while making the other ratepayers better off than they would have been if the elastic customers had decided to self generate.

VI. PRICING STANDBY SERVICE

A. Cost Basis

The first priority in setting standby rates should be to make them as close as possible to the marginal cost of providing the service. However, federal and state regulations require that rates for sales to qualifying facilities be nondiscriminatory. This may mean that if regular retail rates deviate from marginal costs, standby rates should also. It would be discriminatory to charge standby customers marginal costs if revenue requirements were such that regular retail rates exceeded marginal costs. Likewise, standby customers should have the advantage of rates below marginal costs if other customers do.

An example of possibly justified discrimination is the case where discounted standby rates make it feasible for a qualifying facility to cogenerate and reduce the utility's loads during a period when the utility's costs are particularly high, perhaps because generation requirements were underestimated and the utility is having to purchase expensive short-term emergency power. In this case, providing discounted standby power and thereby encouraging cogeneration development might be a cheaper way to obtain capacity and energy than buying it from another utility. The beneficiaries would be the utility's regular ratepayers.

B. Alternative Pricing Arrangements

1. Calculate the Marginal Cost of Standby Service and Adjust as Regular Rates Have Been Adjusted

If the utility has adequate information about the standby loads imposed on it, it can calculate the marginal cost of standby service just as it calculates the marginal cost of service for other classes of customers. Using the rule that standby customers should pay rates which reflect marginal costs to the same extent as customers in the class to which they would otherwise belong, the utility can then develop rates based on those marginal costs.

First, standby customers should generally pay the same energy charges as customers in the class to which they would otherwise belong. If that class has no demand charge and capacity costs are rolled into the energy charge, then the rolled in portion should be segregated and compared to marginal capacity costs in a later step of the process. If, as is the case for IP, certain capacity costs have been rolled into the energy charge as an intraclass bill stabilization measure,[9] the energy charges should be normalized (recalculated without the adjustment) because the standby customers are no longer members of that class and the rationale for the adjustment does not apply to them. To the extent that customer charges for this class differ from marginal customer costs, standby customer charges should be adjusted proportionately. A calculation should then be made for the regular class to determine what percentage of marginal capacity costs are collected in normalized demand charges (or are rolled into energy charges). Marginal capacity costs for the standby class,

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9 IP has an extra 0.25 cents per kilowatt-hour which was moved from the demand charges to the energy charges for large general service customers. The adjustment was made to keep low load factor customers within the class from having very large bill increases when the rates changed. Bary curves for the class also justified the adjustment.

including the cost of specific facilities identified as being installed for these customers, can then be adjusted by the same factor.

In order to make the calculation of standby class marginal costs, detailed information about the standby loads must be available. Particularly with respect to capacity costs, it is unlikely that the utility will have enough information about the level and time pattern of standby loads to calculate these costs accurately. As a result, it will probably be necessary to develop alternative pricing arrangements that could serve as reasonable proxies for the more precise prices that cannot be calculated.

2. Charge Standby Customers the Regular Rates

An alternative which has intuitive appeal and practicality is to calculate the marginal cost of the required facilities installed for standby customers, adjust them by the ratio of capacity charges to marginal costs for the corresponding regular class, as described above, and charge standby customers the customer charge, energy charges, and remaining components of the demand charges for the corresponding class. For example, a standby customer taking service at subtransmission voltage would pay the marginal cost of subtransmission facilities adequate to handle the customer's maximum potential standby demand, adjusted by the ratio between charges and marginal capacity costs for the corresponding regular class. The standby customer would also pay the regular class' customer charge and energy charges, and the transmission and generation component of the regular class' demand charges in any month in which energy was taken (no ratchet).[10]

This option is simple and does not require much additional calculation. It has the advantage of collecting from the standby customers the

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[10] See Section VII.A. for a description of the ratchet.

appropriate share of the costs of metering and local distribution or subtransmission facilities that must be in place even if no power is used. If the customer takes standby service in the summer peak period, it pays the regular summer rate (adjusted for the ratchet). If all standby service is taken in a low-cost period, the lower demand and energy charges are paid and only the special facilities and customer charges are assessed in the rest of the year. To avoid discrimination, eligibility for this rate could be expressed in terms of a low load factor (such as 20 percent) and random patterns of demand rather than limiting its availability to customers with their own generation facilities.

The disadvantage of this option is that is does not reflect the possibility that standby customers using power in a summer peak month, for example, are less likely to need service all month than a regular customer. For example, if standby service in needed only for one week out of the month, the standby customer would pay the full transmission and generation portion of the regular demand charge, even though the standby customer is less likely than a customer with a higher load factor to have been using power at the time of the monthly peak and at other high load hours when reliability is of concern.

Data on maintenance and forced outages on utility-owned generation equipment indicate that outage times average considerably less than a month. The larger units have longer average outage times and steam units have much longer outage times than combustion turbines or diesel units. (See Appendix I.) However, many of these generating units are not operated the way similar equipment would be used by a cogenerator. Furthermore, outages could be caused by the nongenerating portions of the cogenerator's facility. There may be other factors affecting standby loads, such as strikes or fuel supply problems, that would result in longer periods of standby service. Unless we have additional information about the standby loads, we cannot determine how much less cost responsibility the standby customers have than the regular customers.

3. Load Factor Adjustment

Another possible alternative is to have the standby customers indicate the patterns of loads they expect to place on the utility by subscribing to a maximum load and maximum load factor on a monthly or seasonal basis. If the corresponding class on-peak load factor for July is 60 percent and the standby customer subscribes for a July on-peak load factor of 20 percent, a reasonable minimum demand charge, to be collected regardless of the standby customer's actual usage, would be one third of the standard demand charge (less the portion of that charge already accounted for in required facilities charges). If the customer exceeded the subscribed maximum demand or load factor, it would be charged for that month the regular demand charge (less the appropriate portion already accounted for in required facilities charges) adjusted for its actual on-peak load factor as a percent of the class'.

Such a rate would be attractive to any customer in the regular class whose on-peak load factor was significantly below the class average. However, such a rate is justified only for customers whose low on-peak load factors are accompanied by random patterns of electricity consumption. A customer with a 20-percent on-peak load factor and loads that coincide exactly with the hours of highest loss-of-load probability would cause much higher costs to be incurred than a standby customer with a 20-percent on-peak load factor and random patterns of use. To keep customers with nonrandom load patterns from taking advantage of this rate, eligibility requirements would have to be spelled out carefully.

Standby customers on this rate would have the incentive to underestimate their subscription demands and load factors. Using this strategy they could minimize their fixed (subscription) payments; and if their actual usage exceeded the subscription amounts, they would pay only the normal demand charge. Because the utility only saves by providing standby service as compared to regular service if it can anticipate the standby loads and design the system accordingly, it is imperative that the utility have estimates that are as accurate as possible of the patterns and levels of standby loads. Consequently, it may be necessary to impose a penalty of extra charges, above and beyond normal rates, when standby usage exceeds the subscription amounts. For example, these customers could be charged 1.25 times the normal demand charges.

This subscription option has several advantages. First, the utility would have some indication of the standby loads it could expect and could add capacity based on the subscription demands and load factors. Second, to the extent that standby customers have on-peak load factors lower than the class' and accurately predict their usage, they benefit from the cost savings of the utility.

A variation of this subscription service alternative is to dispense with the subscription requirement and apply the load factor adjustment to all standby use. If a standby customer's on-peak load factor is half the S.C. 21 class average, the customer pays one-half the demand charge times the monthly maximum on-peak demand. Conversely, if the standby customer's on-peak load factor is 50 percent higher than the S.C. 21 class average, the customer pays 1.5 times the demand charge times the maximum on-peak demand. This alternative has two advantages over the subscription arrangement: (1) customers have no incentive to play games with the subscription levels and (2) there is no need to develop a cost-based penalty for undersubscribing. The alternative has the disadvantage that the utility will not have the benefit of the subscription data for use in planning and operating the system.

4. Serve Standby Loads with Spot Market Energy and Price Accordingly

Using a variation of real-time pricing, the utility could charge standby customers served at subtransmission level, for example, a customer charge, special facilities charge and transmission charge tied to charges for customers in the corresponding class. Energy costs could be calculated as incurred at the margin. If the utility were making off-system sales or purchases at the margin, the transaction price (plus an appropriate adder for administrative costs in the case of purchases) would be the energy charge for standby service. If the utility were not making off-system sales or purchases at the margin, its own marginal generation costs (plus adder) would be the standby energy charge. These marginal costs would include any start-up costs incurred to serve the standby load. In periods when the region had ample capacity, the spot market price would be relatively low. In times when the regional capacity situation was tight, the price would be higher and could even reach the level of emergency purchases.

Under this approach the utility would not have to predict nor maintain generation capacity for standby loads. The standby customers would have the incentive to time their needs for standby power in periods when the region was most readily able to supply it. However, the level of reliability for the standby customers would probably be lower than under the other options. Since the standby customers would not be paying for capacity, their loads would have a low priority of service in the event the utility ran into generation problems and was unable to buy sufficient emergency power. This option also has the disadvantage that it does not provide equal treatment for all customers. In a period when the region had ample capacity, many customers would be happy to pay spot market prices rather than the utility's normal rates.

C. Maintenance Service

Standby customers who schedule their planned maintenance for periods when the utility has ample capacity available can be served at lower cost than customers who schedule their equipment downtime for other periods of the year. There are two ways to give standby customers the incentive to coordinate their maintenance power needs with the utility.

1. Increase the Number of Rate Periods

Many utilities, including IP, have two seasonal periods in their time-differentiated rates. If more seasonal periods are used for standby demand charges (and perhaps for energy charges as well), the utility can signal to standby customers the months within the broad seasonal periods when maintenance should be scheduled. For example, the months of April and November may be lower cost months from the point of view of generation capacity than the other "winter" months. Standby demand charges for these months could reflect the lower costs, while still being designed on the same basis as the regular rates for the corresponding class. Of course, rates for the other "winter" months would be higher for standby customers because these rates would no longer have the low-cost months of, for example, April and November averaged in the calculation.

2. Discount Demand Charges for Maintenance Service Scheduled Within a Window Identified by the Utility

A simpler but less precise solution is to establish a window within the summer and/or winter season during which standby customers needing maintenance service could schedule their maintenance and receive a discounted demand charge (other than the charges for required facilities). This approach is less precise than the first alternative because the discount will apply to a limited number of months rather than reflecting marginal cost differences in every month. However, this second approach is easily implemented and simpler to administer.

VII. RECOMMENDATIONS FOR ILLINOIS POWER

It appears most realistic to focus on one of the options identified above for standby rates: regular rates, adjusted for costs collected in the required facilities charge, with a load factor adjustment provision. Given the fact that the potential standby customers may not have much more information about their standby loads than the utility, at least in the early years of their operation, it makes sense to defer the subscription alternative. The administrative and technical problems of implementing the spot market approach make it infeasible as a standard rate option. However, this approach could be considered as a possibility for individually negotiated contracts with qualifying facilities.

A. Rates for Standby Customers Based on S.C. 21

Most standby customers will probably be quite large, with demands of at least 200 kilowatts. Therefore, for illustrative purposes we will use IP's rates for large power service, service classification 21 (S.C. 21), as the model for standby rates based on regular rates. S.C. 21 is available for customers with contract capacity of at least 200 kilowatts. Although the rate is available for service at secondary, primary, subtransmission or transmission voltage, our sample rates will apply only to standby customers taking service at primary or subtransmission voltage, the most likely voltage levels for IP's potential qualifying facilities. Exhibit B provides a summary of the preliminary S.C. 21, scheduled to go into effect when the Clinton generating unit is at full power.

The rate includes a fixed monthly customer (facilities) charge, seasonally-differentiated demand charges for on-peak usage with a partial ratchet, diurnally-differentiated energy charges, a transformation charge for customers who do not own their own transformation equipment, and a power factor adjustment. The energy charges are subject to the fuel cost adjustment. Rider S allows S.C. 21 customers to specify a portion of their loads as interruptible and to receive a discounted demand charge for the interruptible portion. In hours when IP's marginal energy costs are high, a charge of $0.10 per kilowatt-hour plus fuel adjustment is applied to energy use in the interruptible portion of the customer's load.

As outlined in Section VI. above, some adjustments are necessary to make the regular rates appropriate for use by standby customers. The development of the standby charges is shown in Exhibit C. (Page 1 of Exhibit C applies to subtransmission customers and page 2 applies to primary customers.) First, while regular customers pay for the subtransmission facilities required to serve them in monthly installments through their demand charges, the intermittent nature of standby loads means that the cost of these facilities must be recovered in separate "required facilities" charges in order to ensure that the utility is fully compensated for the costs it incurs. This first level of the system used by subtransmission standby customers must generally be sized to handle the potential peak load of the customer, whether that load is actually imposed in a given month or not. As we move away from the customer's meter and toward the generation portion of the system, there is greater diversity of loads and a given customer's peak load has less impact on the sizing of facilities. For primary customers it is the primary facility costs which are recovered in the "required facilities charge."

Second, special adjustments made in the regular rates for intraclass equity reasons should be removed unless they are appropriate for standby customers. An example is IP's conversion of a portion of summer demand costs to a 0.25 cents per kilowatt-hour adder to energy charges.

Third, costs recovered in the required facilities charges for standby customers must be removed from the regular demand charges. Otherwise, at least a portion of the cost of subtransmission (or primary) facilities would be collected twice from standby customers.

1. Required Facilities Charges

For subtransmission level standby customers, the first level of the system is the subtransmission system. Thus, the "required facilities" charge should be a fixed monthly charge that, over the year, recovers the annual costs of the subtransmission facilities necessary to handle the potential peak load of the standby customer (the standby contract capacity). In keeping with the two basic requirements for standby rate design--marginal cost basis and consistency with rates for regular customers--we recommend that this charge be calculated as the marginal cost of subtransmission facilities per kilowatt of customer peak demand, adjusted for the ratio of forecasted demand revenues (demand and transformation charges) to marginal demand revenues for the S.C. 21 class.[11] Under the full power rates (those which will be in effect by the time standby charges are in use) developed in compliance with the Illinois Commerce Commission's recent order, this ratio is 1.19. This means that the marginal cost of subtransmission facilities must be increased by 19 percent to make the required facilities charge for standby customers bear the same relationship to

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11 All calculations for the S.C. 21 class include those customers currently in the class and exclude the S.C. 11 customers who will be moved to S.C. 21 in the near future.

marginal cost as the per kilowatt charges for regular S.C. 21 customers, as shown on line (10) of Exhibit C. A similar adjustment is made to the marginal cost of primary facilities to develop a required facilities charge for standby customers served at primary voltage. These adjustments should not be considered a burden on standby customers; they are being treated just as other large customers are being treated. In years when demand revenues are below marginal demand revenues for the S.C. 21 class, standby customers will reap the benefit of required facilities charges below marginal cost.

2. $0.0025 Adjustment to Energy Component

As discussed above, the regular S.C. 21 rate design includes a shift of summer demand revenues to the energy charges. Because the rationale for this shift does not apply to standby customers, we recommend that this shift be reversed. The result is a reduction in energy charges, both on-peak and off-peak, of $0.0025 per kilowatt-hour.

3. Ratchet Adjustment to Demand Charges

The S.C. 21 demand charges include a ratchet feature under which there is essentially as extra $2.50 per kilowatt charge for half of summer demand that is collected in the winter months. Since there are twice as many winter months as summer months (8 vs. 4), the effect of the ratchet is to shift $2.50 ($2.50*0.5*2) per kilowatt of summer demand to the winter period. This ratchet is primarily designed as a transition step from the former rate structure to marginal cost-based, time-differentiated pricing. It is being phased out gradually. Because standby customers may not have demands in winter months, there is no guarantee that the ratcheted costs could be collected from them. In addition, since the standby rate is entirely new, there is no problem of a transition from a previous rate structure. Therefore, it is appropriate to move the ratcheted charges back to the summer peak demand charge. The effect of this adjustment is shown on line (13) of Exhibit C.

4. Adjustment to Demand Charges for $0.0025 Shift

The next adjustment is to move the effect of the $0.0025 per kilowatt-hour removed from energy charges back onto the summer peak demand charge. This is done by calculating the shifted revenue as a percent of summer demand revenues (including ratchet revenues). This percentage gives us the amount by which the summer demand charge calculated so far should be increased. (See line (14) of Exhibit C.)

5. Adjustment to Demand Charges for Subtransmission or Primary

The subtransmission facilities costs for subtransmission customers and primary facilities costs for primary customers are to be collected in the required facilities charge. Therefore, we need to remove these components from the regular demand charge. We recommend that this be accomplished by referring to the share of marginal subtransmission (or primary) revenues in total marginal demand revenues,[12] by season. The subtransmission shares amount to 17 and 6 percent of summer and winter marginal demand revenues, respectively. For primary revenues the shares are 6 percent and 0 percent. Thus the subtransmission-level summer demand charge (adjusted for the ratchet and the revenue shift) was reduced by 17 percent and the winter demand charge by 6 percent. Similar adjustments were made for the primary charge. These adjustments are shown on line (15) of Exhibit C. The rationale for the size of the adjustment is that although the adjusted demand charges do not exactly equal marginal capacity costs, it is reasonable to assume that each component of cost

[12] Marginal demand revenues are the revenues that would be forthcoming if demand charges were set equal to marginal costs.

(generation, transmission, subtransmission and distribution) has been adjusted proportionally.

B. Load Factor Adjustment

Subscription standby rates would be based on the same adjusted regular rates described in the section above. The only difference is in the terms and conditions applicable to service under the subscription rate and the adjustment factor used to establish the demand charge applicable when usage exceeds the subscribed amount.

Under the subscription option, the standby customer would provide the utility annually with the on-peak load factor and maximum standby load for which it wishes to subscribe each month. The utility would use this subscription information in its planning and operating decisions, so it is important that the information be given in advance. Because the standby customers will have only limited experience with their own standby needs at first, they would be allowed to change their subscription levels once a year.

The standby customer would be charged for the subscription level of demand at the regular S.C. 21 standby rate, adjusted by the ratio of the customer's subscription on-peak load factor to the S.C. 21 class on-peak load factor, provided that both the customer's actual maximum demand and on-peak load factor for the month fell within the subscription level. (There would be no discount for loads or load factors below the subscription amount, because the utility would have planned and invested to supply the subscription level of demand.) If the on-peak load factor or the peak demand or both exceed the subscription levels, the penalty demand charge would be imposed on the actual peak demand, adjusted by the ratio of the actual on-peak load factor to the S.C. 21 class on-peak load factor.

For example, suppose the standby customer subscribes for a peak demand of 2,000 kilowatts and an on-peak load factor of 20 percent for the month of June. The 20-percent load factor is only 40 percent of the S.C. 21 class' on-peak load factor for summer months of 50 percent. If the standby customer's usage in within the subscribed limits, the demand charge for June will be 40 percent of the regular S.C. 21 demand charge (adjusted) times 2,000 kilowatts. If, instead, the standby customer has peak of 3,000 and a load factor of 60 percent, the penalty will be invoked. The demand charge will be 3,000 kilowatts times 60/50 of the regular demand charge (as adjusted) times 1.25.

The 25-percent surcharge reflects the fact that IP would be planning on the basis of the subscription levels. It may have to make emergency arrangements for backup generation or its customers may experience reduced service reliability as a result of the standby customer's failure to keep usage within the subscribed amounts.

If there is concern about the ability or willingness of standby customers to subscribe accurately, the load factor adjustment can be applied to actual standby usage without requiring subscriptions. In this case, there is no penalty factor.

C. Maintenance Scheduling Incentives

We propose that maintenance service be provided under the same schedule as backup service. Together we refer to them as standby service. However, there are months within the summer (and especially the winter) period when costs are lower than the seasonal average. It is in these months that IP should encourage standby customers to do their own maintenance and impose their standby loads. One way to do this is to have standby demand charges which change monthly. Since this alternative is administratively complicated, a less precise, but more feasible way to encourage standby customers to schedule their maintenance in IP's low cost months is to give a discount on the demand charge if maintenance is scheduled in a window period identified each year by IP. An analysis of the relative monthly loss-of-load probabilities (LOLP) forecasted by IP for the next 20 years shows that the months with the lowest and second lowest LOLPs in the winter have LOLPs that average 32 and 42 percent, respectively, of the average monthly LOLP in the winter. For the lowest month in the summer the figure is 43 percent. (See Appendix II.) This implies that a demand charge discount on the order of 50 percent is warranted if the standby customer schedules maintenance for one of the months identified by IP as the maintenance windows.[13]

Line (16) on Exhibit C shows the adjustment to the winter demand charge that is warranted if the 50-percent discount is in effect for two of the winter months. The seasonal demand costs (monthly cost times 8 months) are divided by seven to reflect the six months of full charges and two months at a 50-percent discount. This adjustment leaves the rate revenue neutral with respect to the discount for two months.

Unfortunately, it is not always possible for IP to stick to its own maintenance schedule. As a result, a month identified as a low cost month may turn out to be a high cost month because IP has had to shift its own maintenance schedule. It would be especially beneficial to IP and its ratepayers if standby customers could shift their own maintenance schedules on relatively short notice

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13 The percentages above are based on an analysis of generation capacity cost variations only, while the demand charge to which the discount would apply recovers both generation and transmission costs. Transmission cost variations are probably smaller across the months within a season. This means that the 50-percent discount is probably generous.

as IP identified a revised maintenance window. As a reward for this, we propose that IP consider giving a 100-percent discount for maintenance loads shifted in response to a change in IP's announced maintenance window.

D. Supplemental Service

We propose that supplemental service for qualifying facilities be provided under the regular rate for which their supplemental service characteristics qualify them. This recommendation is a preliminary one, based on the assumption that the supplemental loads will have load factors and characteristics which are similar to those of regular customers. If it turns out that supplemental service for some qualifying facilities is very intermittent in nature, it may be appropriate to specify new qualifications for the regular rates, and assign customers not meeting those qualifications (whether they are qualifying facilities or not) to the standby rate.

IP is not willing to provide the Rider S discount for standby service. Rider S is largely an economic development rate at this time, and is limited in availability. To keep customers taking their supplemental service under Rider S of the S.C. 21 rate from effectively getting standby service at the Rider S rate, it will be necessary to meter both the electricity production and loads of these customers. When electricity production falls below the normal level, loads equal to the difference between the normal and actual level of production will be charged at the standby rate, while remaining power taken from the utility will be charged at the Rider S rate. Exhibit D illustrates the loads charged under the two rates. We recommend that the costs of the additional metering equipment required by this arrangement will be collected through a negotiated administrative fee; these costs are not specified in the rate itself.

VIII. SAMPLE TARIFF SHEET

Exhibit A is a sample tariff sheet developed in conjunction with IP staff. The tariff sheet reflects our recommended price and nonprice terms and conditions for standby service.

HSP:pjl

Exhibit B

ILLINOIS POWER COMPANY
HIGHLIGHTS OF
PRELIMINARY S.C. 21 RATE (FULL POWER)
(FOR SERVICE AT 34.5KV OR ABOVE)

	Summer	Winter
Facilities Charge ($/mo)	$600.00	$600.00
Demand Charge		
($/kW of on-peak demand during month)	$15.41	
($/kW of on-peak demand during month up to 50% of summer peak demand)		$5.50
($/kW of on-peak demand in excess of 50% of summer peak demand)		$3.00
Energy Charge*		
(Cents per on-peak kWh)	4.17	4.17
(Cents per off-peak kWh)	2.87	2.87
Transformation Charge		
($/kW of peak demand in last 12 months)	$0.50	$0.50

Power Factor Adjustment
(There is an adjustment for lagging power factors)

*Includes estimated test year fuel cost adjustment of 0.17 cents/kWh

Summer = June 15 - Sept. 14
Winter = Sept. 15 - June 14
On-Peak = 10 a.m. - 9 p.m., Mon-Fri, except holidays
Off-Peak = Other hours

RIDER S

Under this rider, a customer may identify a certain amount of capacity (demand) as interruptible. The charge for the interruptible capacity is $0.10/kW/month. Energy taken under the rider is charged at the S.C. 21 rate unless it is used in a period in which IP anticipates operating high cost units or or emergency purchases, in which case the charge is 10 cents/kWh plus fuel cost adjustment.

ILLINOIS POWER COMPANY
DERIVATION OF SAMPLE
STANDBY RATE FOR SC21 CUSTOMER
SERVED AT SUBTRANSMISSION VOLTAGE

Exhibit C
Page 1 of 2

ASSUMPTIONS:

(1)	Marginal cost of subtransmission facilities ($/kW/mo)	$0.80
	Monthly S.C.21 demand charge ($/kW/mo)	
(2)	Summer (including ratchet on winter charge #1)	$17.91
(3)	Winter	$3.00
	Marginal subtransmission revenues for S.C.21 as a percent of generation + transmission + subtransmission marginal revenues (Percent)	
(4)	Summer	17%
(5)	Winter	6%
	Ratio of adjusted proposed to marginal demand revenues	
(6)	for S.C.21 class	1.19
(7)	0.25 cent/kwh adjustment as percent of total summer demand revenues without a winter ratchet (Percent)	14.21%

	FACILITIES CHARGE		
(8)	($ per month)	$600.00	
	REQUIRED FACILITIES CHARGE ($ per kW of contract capacity per month)		
(9)	Marginal cost of subtransmission	$0.80	
(10)	Adjustment for ratio of proposed to marginal revenues (9)x(6)	$0.95	
	ENERGY CHARGES (excludes 0.25/kWh cent adj.)		
(11)	Peak periods ($/kWh)	$0.0375 + fuel adjustment	
(12)	Off-peak periods ($/kWh)	$0.0245 + fuel adjustment	
	DEMAND CHARGES ($/kW/month)	Summer	Winter
(13)	S.C. 21 demand charge adjusted for ratchet	$17.91	$3.00
(14)	Adjusted for 0.25 cents/kWh (13)x[1+(7)] (Summer only)	$20.46	$3.00
(15)	Adjusted for subtransmission costs (14)x[1-(4)] or (14)x[1-(5)]	$16.98	$2.82
(16)	Adjusted for 50-percent discount in two winter months (15)x8/7		$3.22

#1 Equal to the $15.41/kW demand charge plus the $2.50 surcharge on winter demand adjusted for number of months in each season and its applicabilty to 50% of contract capacity.

Source: NERA Worksheet, "IPC Marginal Subtransmission Costs Adjusted for Coincidencs (SC21)," IPC Preliminary Rates for SC 21 data supplied by IPC, NERA worksheets "Components of Marginal Revenues Rate SC 21, 1986," "Calculation of Ratio of Proposed to Marginal Demand Revenue SC 21," and "IPC S.C. 21 Billing Determinants."

ILLINOIS POWER COMPANY
DERIVATION OF SAMPLE STANDBY RATE FOR SC21 CUSTOMER SERVED AT PRIMARY VOLTAGE

ASSUMPTIONS:

(1)	Marginal cost of primary facilities ($/kW/mo)	$0.47
	Monthly S.C.21 demand charge ($/kW/mo)	
(2)	Summer (including ratchet on winter charge #1)	$21.36
(3)	Winter	$3.00
	Marginal primary revenues for S.C.21 as a percent of generation + transmission + subtransmission + primary marginal revenues (Percent)	
(4)	Summer	6%
(5)	Winter	0%
	Ratio of adjusted proposed to marginal demand revenues	
(6)	for S.C.21 class	1.19
(7)	0.25 cent/kwh adjustment as percent of total summer demand revenues without a winter ratchet (Percent)	14.21%

	FACILITIES CHARGE	
(8)	($ per month)	$200.00
	REQUIRED FACILITIES CHARGE ($ per kW of contract capacity per month)	
(9)	Marginal cost of subtransmission	$0.47
(10)	Adjustment for ratio of proposed to marginal revenues (9)x(6)	$0.56
	ENERGY CHARGES (excludes 0.25/kWh cent adj.)	
(11)	Peak periods ($/kWh)	$0.0385 + fuel adjustment
(12)	Off-peak periods ($/kWh)	$0.0255 + fuel adjustment

	DEMAND CHARGES ($/kW/month)	Summer	Winter
(13)	S.C. 21 demand charge adjusted for ratchet	$21.36	$3.00
(14)	Adjusted for 0.25 cents/kWh (13)x[1+(7)] (Summer only)	$24.40	$3.00
(15)	Adjusted for primary costs (14)x[1-(4)] or (14)x[1-(5)]	$22.93	$3.00
(16)	Adjusted for 50-percent discount in two winter months (15)*8/7		$3.43

#1 Equal to the $18.86/kW demand charge plus the $2.50 surcharge on winter demand adjusted for number of months in each season and its applicabilty to 50% of contract capacity.

Source: NERA Worksheet, "IPC Marginal Primary Costs Adjusted for Coincidence (SC21)," IPC Preliminary Rates for SC 21 data supplied by IPC, NERA worksheets "Components of Marginal Revenues Rate SC 21, 1986," "Calculation of Ratio of Proposed to Marginal Demand Revenue SC 21," and "IPC S.C. 21 Billing Determinants."

Exhibit D

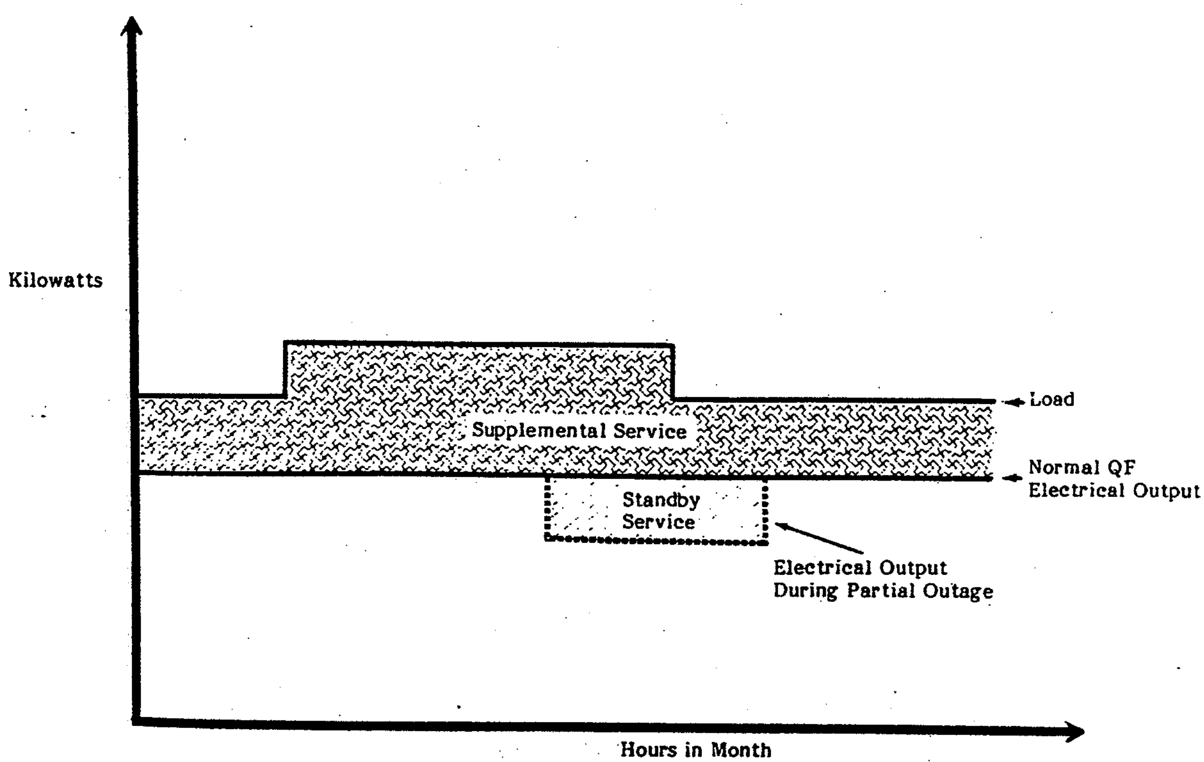


Illustration of How Supplemental and Standby Service Will be Differentiated for Standby Customers Taking Supplemental Service Under Rider S.

Appendix I

AVERAGE OUTAGE LENGTH OF GENERATING FACILITIES
FOR THE TEN-YEAR PERIOD 1965-1974

	Forced*	Maintenance**	Planned***
	(Hours)		
	(1)	(2)	(3)
1) Jet Engine	58.6	22.0	103.5
2) Gas Turbine	50.9	35.4	122.9
3) Diesel	39.5	16.1	15.9
4) Fossil			
60-89 MW	52.2	62.9	510.2
90-129 MW	45.8	65.9	461.1
130-199 MW	43.5	61.0	439.7
200-389 MW	53.9	78.5	512.8
390-599 MW	60.2	94.4	551.3
600+ MW	64.3	97.4	598.3

*Forced Outage — The occurrence of a component failure or other condition which requires that the unit be removed from service immediately or up to and including the very next weekend.

**Maintenance Outage — The removal of a unit from service to perform work on specific components which could have been postponed past the very next weekend. This is work done to prevent a potential forced outage and which could not have been postponed from season to season.

***Planned Outage — The removal of a unit from service for inspection and/or general overhaul of one or more major equipment groups. This is work which is usually scheduled well in advance (e.g., annual boiler overhaul, five-year turbine overhaul).

Source: Edison Electric Institute, Equipment Availability Task Force of the Prime Movers Committee, "Report on Equipment Availability ability for the Ten-Year Period, 1965-1974."

Appendix II

ILLINOIS POWER COMPANY
PROJECTED LOSS OF LOAD HOURS
1985-2004

	JAN.	FEB.	MAR.	APR.	MAY	JUNE	JULY	AUG.	SEP.	OCT.	NOV.	DEC.	TOTAL
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
1985	5.90	2.71	4.17	0.74	3.12	2.60	7.38	9.44	7.26	3.36	1.76	4.89	33.33
1986	9.76	2.41	0.99	1.11	1.26	5.35	6.58	6.28	3.98	1.79	2.70	1.90	44.11
1987	10.85	2.15	1.61	0.62	2.01	3.60	5.95	6.86	4.97	2.96	2.33	2.51	46.42
1988	4.47	2.21	0.42	2.98	2.91	2.71	2.86	3.35	5.83	2.13	0.36	0.65	30.88
1989	1.34	1.96	3.40	1.55	2.40	3.17	2.08	2.49	1.42	1.45	0.48	0.55	22.29
1990	1.22	1.91	3.45	6.95	1.65	1.51	5.30	6.02	7.49	7.57	1.24	1.43	45.74
1991	3.16	3.34	4.21	7.26	2.90	7.48	6.29	7.30	1.45	3.23	1.34	1.12	49.08
1992	4.33	2.75	5.46	7.86	12.15	11.64	7.50	8.93	1.65	1.88	2.10	1.92	69.07
1993	1.25	0.34	0.57	3.68	3.82	1.97	2.26	2.65	2.55	3.74	0.90	1.36	25.09
1994	1.37	2.34	2.91	4.70	1.73	1.62	5.38	5.85	1.88	3.46	1.54	1.16	33.94
1995	4.57	4.07	20.42	15.90	8.44	6.68	6.54	6.97	1.96	2.52	1.67	1.16	80.70
1996	4.57	2.50	4.90	8.17	2.01	2.35	7.81	8.13	10.31	9.07	3.34	1.99	65.15
1997	6.45	3.83	7.20	11.00	4.67	8.16	9.08	9.47	2.28	3.56	2.84	1.92	70.46
1998	7.88	4.19	8.18	11.71	13.30	13.25	10.48	10.90	2.75	4.29	3.04	2.15	92.12
1999	9.11	11.09	13.56	34.70	16.39	4.45	11.85	12.39	18.51	16.31	5.16	3.32	156.84
2000	11.39	3.41	9.81	13.59	3.52	4.06	13.42	14.03	4.67	8.27	3.87	3.13	92.17
2001	13.15	13.82	22.43	30.17	16.40	14.70	15.11	15.98	3.65	7.40	4.04	2.96	159.81
2002	10.93	6.65	11.62	15.03	3.90	5.01	16.48	17.23	21.86	19.57	9.44	5.04	142.76
2003	11.58	8.12	10.72	16.03	8.44	16.77	18.91	20.12	4.88	9.97	5.99	4.13	134.66
2004	19.04	8.60	16.57	24.15	24.54	23.74	21.42	22.37	5.95	10.84	5.94	5.79	188.85

Note: Summer = June - September.
Winter = October - May

Source: IP worksheets "Monthly Summaries for the Years 1985-2004,
Loss of Load Hours by Rating Period."

PERCENT OF ANNUAL

	JAN.	FEB.	MAR.	APR.	MAY	JUNE	JULY	AUG.	SEP.	OCT.	NOV.	DEC.	TOTAL	SUMMER SEASON AVG.	SUMMER LOWEST MONTH	SUMMER LOWEST AS % AVG.	WINTER SEASON AVG.	WINTER LOWEST MONTH	WINTER LOWEST AS % AVG.	WINTER SECOND LOWEST MONTH	WINTER 2ND LOWEST AS % AVG.
										(Percent)											
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)
1985	11.06	5.08	7.82	1.39	5.85	4.88	13.84	17.70	13.61	6.30	3.30	9.17	100.00	12.51	4.88	38.95%	6.25	1.39	22.21%	3.30	52.83%
1986	22.13	5.46	2.24	2.52	2.86	12.13	14.92	14.24	9.02	4.06	6.12	4.31	100.00	12.58	9.02	71.74%	6.21	2.24	36.13%	2.52	40.57%
1987	23.37	4.63	3.47	1.34	4.33	7.76	12.82	14.78	10.71	6.38	5.02	5.41	100.00	11.51	7.76	67.35%	6.74	1.34	19.81%	3.47	51.46%
avg 85-87	18.85	5.06	4.51	1.75	4.35	8.25	13.86	15.57	11.11	5.58	4.81	6.29	100.00								
%of seas.	36.3%	9.9%	8.8%	3.4%	8.5%	16.9%	28.4%	31.9%	22.8%	10.9%	9.4%	12.3%									
1988	14.48	7.16	1.36	9.65	9.42	8.78	9.26	10.85	18.88	6.90	1.17	2.10	100.00	11.94	8.78	73.49%	6.53	1.17	17.95%	1.36	20.83%
1989	6.01	8.79	15.25	6.35	10.77	14.22	9.33	11.17	6.37	6.51	2.15	2.47	100.00	10.27	6.37	62.01%	7.36	2.15	29.25%	2.47	33.55%
1990	2.67	4.18	7.54	15.19	3.61	3.30	11.59	13.16	16.38	16.55	2.71	3.13	100.00	11.11	3.30	29.72%	6.95	2.67	38.39%	2.71	39.01%
1991	6.44	6.81	8.58	14.79	5.91	15.24	12.82	14.87	2.95	6.58	2.73	2.28	100.00	11.47	2.95	25.75%	6.76	2.28	33.73%	2.73	40.36%
1992	6.27	3.96	7.91	11.38	17.59	16.85	10.86	12.78	2.39	4.17	3.04	2.78	100.00	10.72	2.39	22.28%	7.14	2.78	38.94%	3.04	42.58%
1993	4.98	1.36	2.27	14.67	15.23	7.85	9.01	10.56	10.16	14.91	3.59	5.42	100.00	9.40	7.85	33.56%	7.80	1.36	17.37%	2.27	29.10%
1994	4.04	6.89	8.57	13.85	5.10	4.77	15.85	17.24	5.54	10.19	4.54	3.42	100.00	10.85	4.77	43.99%	7.07	3.42	48.31%	4.04	57.10%
1995	5.66	5.04	25.30	19.58	10.46	8.28	5.10	8.64	2.30	3.12	2.07	1.44	100.00	6.83	2.30	33.74%	9.08	1.44	15.82%	2.07	22.79%
1996	7.01	3.84	7.52	12.54	3.09	3.61	11.99	12.48	15.83	13.92	5.13	3.05	100.00	10.97	3.61	32.87%	7.01	3.05	43.56%	3.09	44.06%
1997	9.15	5.44	10.22	15.61	6.63	11.58	12.89	13.44	3.24	5.05	4.03	2.72	100.00	10.29	3.24	31.46%	7.36	2.72	37.04%	4.03	54.78%
1998	8.55	4.55	8.88	12.71	14.44	14.38	11.38	11.83	2.99	4.66	3.30	2.33	100.00	10.14	2.99	29.43%	7.43	2.33	31.42%	3.30	44.43%
1999	5.81	7.07	8.65	22.12	10.45	2.84	7.56	7.90	11.80	10.40	3.29	2.12	100.00	7.52	2.84	37.71%	8.74	2.12	24.22%	3.29	37.65%
2000	12.36	3.70	9.56	14.74	3.82	4.40	14.56	15.22	5.07	8.97	4.20	3.40	100.00	9.81	4.40	44.89%	7.59	3.40	44.72%	3.82	50.31%
2001	8.23	8.65	14.04	18.88	10.26	9.20	9.45	10.00	2.28	4.63	2.53	1.85	100.00	7.73	2.28	29.53%	8.63	1.85	21.46%	2.53	29.31%
2002	7.66	4.66	8.14	10.53	2.73	3.51	11.54	12.07	15.31	13.71	6.61	3.53	100.00	10.61	3.51	33.08%	7.20	2.73	37.97%	3.53	49.06%
2003	8.60	6.03	7.96	11.90	6.27	12.45	14.04	14.94	3.62	6.66	4.45	3.07	100.00	11.27	3.62	32.17%	6.87	3.07	44.66%	4.45	64.80%
2004	10.08	4.55	8.77	12.79	12.99	12.57	11.34	11.85	3.10	5.74	3.15	3.07	100.00	9.71	3.10	31.59%	7.64	3.07	40.11%	3.15	41.21%
AVG.	10.19	5.65	8.93	12.25	8.31	9.35	12.36	13.58	9.64	8.25	3.90	3.67				42.78%			32.15%		42.29%

Information Request TEC-3-33

Please provide a copy of "Line Extension Policies in the Restructured U.S. Electric Industry' (April 2001).

Response

A copy is provided as Attachment TEC-3-33.

Att. TEC-3-33

Line Extension Policies in the Restructured US Electric Industry

Hethie Parmesano & Amparo Nieto

Marginal Cost Working Group

April 2001

NATIONAL ECONOMIC RESEARCH ASSOCIATES

n/e/r/a
Consulting Economists

Rationale for Up-front Contributions Required by Line Extension Policies:

- Three basic reasons for customers to contribute up-front to hook-up costs:

1) to give efficient signals to consumers locating in remote areas;

2) to avoid a cross-subsidy from low-cost customers to high-cost customers, since tariffs are based on average costs; and

3) to avoid stranded costs due to price cap or prudence review if the customer with high hook-up costs leaves and is not replaced.

New Risks in a Restructured World

- With vertical unbundling the utility becomes mostly (or entirely) a delivery company.
    - Profits from higher-than-cost generation charges can no longer be used to offset losses on distribution.
    - Even if utility retains some generation, requirements for unbundled tariffs and accounting separation prevent cross-subsidization.
- With rate freeze or PBR programs: tariffs cannot be changed except by a formula tied to inflation, so higher-than-average hook up costs cannot be recovered through tariffs.
- Distributed generation is a serious threat (leads to strandable distribution costs).

➡ These factors point to higher up-front charges for line extensions.

Observed Reforms in Line Extension Policies

- Customers' contributions towards the cost of the construction are increased.
- Revenue tests are still performed, but only estimated revenues from delivery services are now considered, or
- Instead of revenue test, standard limits (or generic allowances) are specified for different types of users, and customers must pay up-front the difference between the installed cost and allowances, if any.
- In most cases, refunds are granted, but there is an increased tendency to tie these refunds to additional tariff revenues or up-front payments from new customers connecting to the line.

Survey

Ten US utilities' line extension policies have been surveyed:

1.	Arizona:	Arizona Public Service Company
2.	California:	San Diego Gas and Electric
3.	Georgia:	Georgia Power Company
4.	Illinois:	Commonwealth Edison Company
5.	Maine:	Central Maine Power Company
6.	Massachusetts:	Nantucket Electric Company
7.	New Jersey:	Public Service Electric and Gas Company
8.	New York:	Rochester Gas and Electric
9.	Pennsylvania:	PECO Energy Company
10.	Texas:	Texas Utilities Electric Company

- Except Arizona, Georgia and Texas, all line extension policies have been revised for retail access.

Key features of line extension policies

1. Differentiated treatment: by customer type underground versus overhead, etc.

2. Use of up-front payment vs. monthly charges (or combination of both).

3. Criteria for allowances (footage basis, revenue test, generic dollar amounts)

4. Refund mechanisms, e.g.:

   - is the utility providing the refunds from tariff revenues?

   - are new customers required to pay a refund to the original customer?

1. Differentiation

- Rules for connection payments, allowances and refunds often vary by:
  a) customer type, e.g: (1) individual residential; (2) residential land-developer, (3) commercial and industrial; (4) irrigation.
  b) type of service: (1) Underground vs. (2) Overhead.
  c) phase: (1) Single-phase vs. (2) Three-phase.
- Most utilities provided differentiated procedures by customer type.
- Others (e.g. RG&E) combine customer type, service and phase. CMP and PECO use phase.
- Other utilities (e.g. ComEd) do not give a differentiated treatment.

2. Up-front contributions

- Most of the surveyed US utilities request up-front contributions from their customers (usually, for the cost in excess of allowances):
  - APS, SDG&E, GPC, ComEd, CMP, RG&E, Texas Utilities.
- Two of the utilities offer payment options to residential customers: Nantucket Electric Company, PSG&E.
  - Nantucket: residential customers may choose between an up-front payment or monthly payments when the payable amount is above $1,500.
  - PSG&E: customers may choose between an up-front payment or a monthly revenue guarantee. Up-front payments for underground extensions are calculated from specific $ amounts per foot.
- PECO does not require up-front payment. Instead, minimum annual revenue guarantees are required.

2. Up-front contributions: Issue

- Should contribution cover just installed costs?
- Should contribution also cover O&M and eventual replacement costs?
  - We have found none than cover more than installed cost of facilities.
  - This means some cross-subsidies continue within distribution tariffs.

3. Allowances

- Allowances (i.e. the portion of line extension that is not recovered up-front) are typical.
- The surveyed utilities have different mechanisms to set allowances:
  - a) Standard feet line allowance
  - b) Dollar amount allowance
  - c) Revenue-based allowance or revenue test (typically, a formula that takes into account the future revenues from standard tariffs, or from the portion of the bundled tariff that corresponds to distribution).
- Some issues that may vary among utilities are:
  - ➢ are meter costs part of the revenue used to set the allowance?
  - ➢ are revenue cycle services part of the revenue used to set the allowance?

3. Allowances

- **APS:** Thee different methods are applied.
  - Footage basis, applied to residential customers only, if extension < 2,000 feet and construction costs < $25,000. Free extension for the first 1,000 feet.
  - Revenue test, applicable when construction costs < $25,000. The allowance is based on the annual estimated revenues times 2.
  - "Feasibility test", applicable when construction costs > $25,000. Extension is free if it is considered to provide an adequate rate of return.
- **Central Maine Power Company**: No allowances, but meter, transformer, overhead service drop and O&M costs are excluded from the up-front payment.
- **Commonwealth Edison:** The line extension is free if the estimated cost of the extension does not exceed the greater of:

  (a) the cost equivalent to 250 feet of single-phase overhead line per customer, or

  (b) the estimated annual delivery services revenue per customer.

3. Allowances

- **Georgia Power Company**:
  - Revenue Test is computed. Free extension if the net cost of the extension is below 3½ times (for overhead) or 2½ (for underground) the estimated annual revenue to be derived from the service.
  - Footage allowance may be applied for single-phase customers if this is more advantageous to the customer than the revenue test.
- **Nantucket Electric company:**
  - Footage basis is used to set allowances for residential customers and residential land developers.
  - Revenue test, based on the distribution tariff applicable during the first year, for commercial and industrial.
- **PECO**: Footage allowances for single-phase customers. Total dollar amount ($60,000) for multi-phase customers.

3. Allowances

- **PSG&E**: Previously revenue test; currently:
    - residential customers have a dollar amount allowance ($0.50 per estimated annual kWh usage). Extensions less than 2,500 feet are free.
    - no standard allowances for non-residential: customers may be required to pay full cost.
- **RG&E:** footage-based allowances (100 feet for residential; 500 feet for non-residential single-phase; 300 feet for non-residential three-phase).
- **SDG&E**: the old line extension rules provided allowances in the form of "free-footage". The new rules have converted the past level of "free-footage" into:
    - a “dollar” amount for residential ($1,170 per meter or unit);
    - a distribution revenue-based allowance for non-residential.
- **Texas**: Footage allowances for small loads (estimated demand < 20 kW). Revenue test for other extensions.

3. Allowances: Issue

- Are meter charges included in computation of the revenue-based allowance? Some examples:
  - ➢ In California, meters are provided with no up-front charge only if they are revenue-justified:
    - standard meter installed costs are part of the tariff revenues considered to compute allowances;
    - however, if allowances do not cover the actual costs of meter to be installed, users are required to pay the cost of the meter up-front.
  - ➢ Central Maine Power Company does not require up-front payment for the meter.

3. Allowances: Issue

- Are Revenue Cycle Service costs part of the revenue-based allowances?
  - Some revenue-based allowances may include charges that correspond to potentially competitive services, such as revenue cycle services (meter reading, billing, etc.)
  - This is a potential source of risk for the utility, since customers may receive credits for these services when they switch supplier.
  - In California, meter services, meter reading and billing, and payment services (RCS) are no longer included in the line extension allowance calculation (Decision 99-12-046).

4. Refunds

- Up-front payments are generally refundable, at no interest.
- The period over which refunds may be granted varies among utilities (usually the first 5 or 10 years).
- There are several mechanisms to provide refunds:

  a) refunds coming from up-front contributions made by new customers connecting to the existing line extension;

  b) refunds provided by the utility, either from higher revenues than expected from the original customer, or from revenues from new customers;

  c) lower costs of line extension than estimated when up-front payment was calculated.

- Temporary services and customers of doubtful permanency are generally not eligible for refund.

4. Refunds

- **APS**: Maximum of 5 years to get refunds:
  - refunds are based on the results of a survey conducted by the company after five years from the start of service. Refunds are equal to the difference between the original up-front contribution and the contribution amount that would result had this been calculated at the time of the survey.
  - for irrigation customers, refunds to the original customer are based on the advance collected from new customers connecting to the line.
- **CMP:** Maximum of 5 years to get refunds:
  - for single-phase extensions, a new customer connecting to the line must pay up-front a *Development Incentive Payment* (DIPs), expressed as $1 per foot of shared line. These DIPs are used to provide refunds to the original customer.
  - users of three-phase extensions do not get any refunds.

4. Refunds

- **ComEd**: up-front payments are refundable for a period of ten years, based on changed circumstances (affecting actual delivery service revenue) or shared use of the connection assets.
- **Georgia Power**: maximum of five years to get a refund. It is determined by recalculating the extension when a new customer is connected to the line. If such recalculation would decrease the original parties' contribution account, a refund is made, and the new customer or load is required to make contribution.
- **Nantucket Electric**:
  - for residential customers: during the first 5 years of service, any new customer connected to the service must make a prorated contribution to the payment of the original customer, based on a equitable apportioning of the total estimated construction cost (less allowances) between the customers.
  - commercial and industrial: between 12 and 36 months after start of delivery of electricity, customers may request the company to recalculate the construction advance payment using actual costs and revenues to determine if a refund is warranted.

4. Refunds

- **PECO**: recalculation of revenue guarantee within the first 3 years.
  - Based on revenue guarantees provided from additional customers connecting to the line extension. The remaining amount to be guaranteed for existing line extension is reapportioned for all customers including the new customers.
- **PSG&E:** refunds may be granted within the first 10 years.
  - Residential: the company makes a refund to the customer as new customers are supplied along the extension, based upon the point where the additional customer is connected.
  - Residential land developer: The utility returns to the developer $0.50 per estimated annual kWh usage when street lights have been installed or new buildings abutting on such extensions have been framed and roofed.
  - Commercial & industrial: every year PSG&E refunds an amount equal to: [$3.00 * the sum of that year's monthly kilowatts billed to the customer]. Refunds continue each year until full refund of the sum deposited.

4. Refunds

- **RG&E:** Refunds may be granted during the first five years.
  - New customers connecting to an existing extension make prorated contributions to the payment of the original customer based on a equitable allocation of the total estimated construction cost (less allowances).
- **SDG&E**: Maximum of 10 years to get refund.
  - SDG&E offers two payment options: (a) full up-front payment, fully refundable; (b) 50% discounted up-front payment, non-refundable.
  - When new customers connect to the line, if the cost of service wire, meter and service transformer is less than the customer allowance, the resulting excess allowance is granted as a refund to the original customer.
- **Texas Utilities**: No refunds are granted.

Alternatives to New Connection

- Some line extension policies require that, when a utility requires a customer to pay a contribution toward the construction of extending utility power lines to a remote location, the utility must provide information about on-site renewable energy technology options.

- Arizona, Colorado, New Mexico and Texas have regulations that require electric utilities to let consumers know the costs and benefits of power line extensions versus installation of renewable energy systems.

- In Arizona, a utility is required to perform a cost/benefit analysis to compare line extension with stand-alone photo voltaic systems. Arizona Public Service offers a financing package for PV installation.

Principles for Line Extension Policies

1. **Equity:**

- In absence of up-front payments, there is cross-subsidy from low-cost customers to high-cost customers, since tariffs are based on average costs.

- Users who paid up-front for a line extension may consider it "unfair" if new customers connect to the line with no contribution.

Principles for Line Extension Policies

2. Efficiency and consistency between the distribution tariff and the line extension policy.

- Up-front payments that reflect the real cost of connection give efficient signals about location and the benefits of distributed generation alternative.

- Up-front payments that cover what soon become sunk costs allow distribution rates closer to the distribution marginal costs, and therefore, to provide more efficient signals to users.

- Cost studies used to set distribution rates should take into consideration costs recovered up-front so there is no double-counting.

Basic Recommendations

- **Allowances:**
  - Allowances should ideally be established based on the cost of connections typical for a customer of each voltage level and customer classification.
  - Distribution tariffs can then include the typical cost and be recovered from all users.
  - Special (higher) allowances could be granted to low-income customers or as a spur to rural electrification, however, ideally these subsidies should be provided directly by a government agency (to avoid cross-subsidization).
- **Up-front payments:** These should cover the cost of the extension in excess of the allowances, with provision for monthly payments, if a one-time payment would be onerous for customers.

Basic Recommendations

- **Meters:**
  - If metering is competitive, the utility (like any meter supplier) should be free to charge up front or some other way for it.
  - Up-front payment with a refund of the salvage value if customer chooses another meter supplier prevents stranded meter costs.
- **Subsequent Customers**:
  - Allowances and upfront payments should also be calculated for subsequent customers who use facilities paid for by other customers' up-front payments.

Basic Recommendations

- **Refunds:** refunds should be granted to the extent that up-front contributions for existing facilities are obtained from new customers connecting to the line.
  - The distributor would collect the money from the new user and send it to the original customer, if that customer(s) is still located on the premises.
  - The refund would be computed as a pro-rata share (based on subscribed demand or feet of line used) of the original contribution for the shared facilities.
  - The refunds to which the first user is entitled would not include any interest on his up-front payment.
  - Refunds would be made only up to the sum paid up front. After five years from the date of the original payment, no refund would be collected or made.

Information Request TEC-3-34

Please provide a copy of "Line Extension Policies-Due for a Change?" (April 3-4, 2002).

Response

A copy is provided as Attachment TEC-3-34.

Att. TEC-3-34

Line Extension Policies - Due for a Change?

Hethie Parmesano

Marginal Cost Working Group

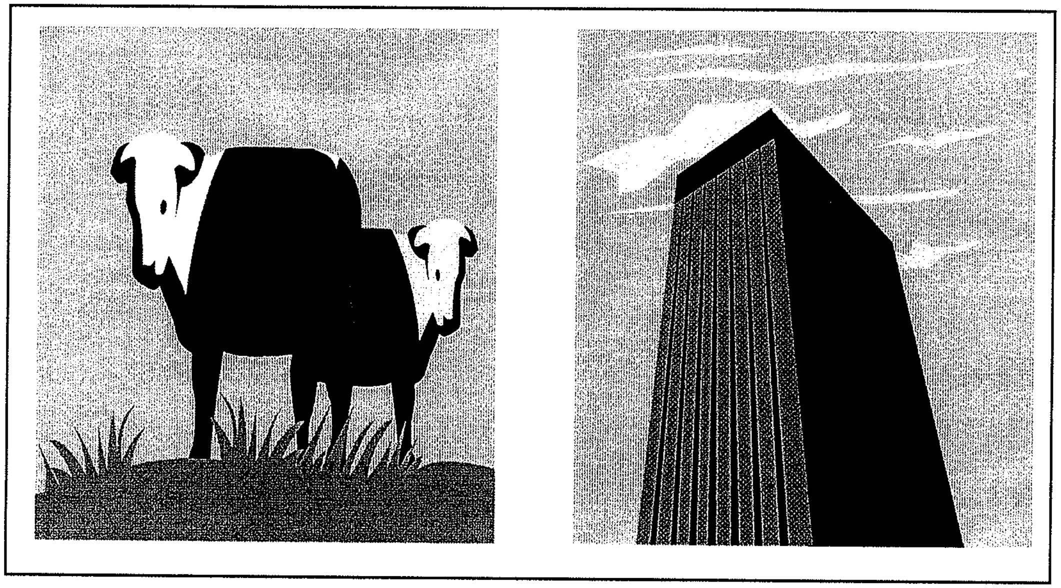
Las Vegas, Nevada

April 2000

NATIONAL ECONOMIC RESEARCH ASSOCIATES

n/e/r/a
Consulting Economists

Not all customers are alike.



- The investment necessary to hook up a customer can vary significantly.
- Consumption by customers with similar hook-up costs can vary significantly.

Line extension policies traditionally have required customers with high hook-up costs to contribute up-front to the cost of hooking them up.

Typical Line Extension Policies

1- Utility pays for first X feet of line; customer pays for the rest.

2- Utility pays for first X feet of line (or $Y of investment); customer pays for the rest unless annual revenues from customer are expected to be at least Z times investment cost.

3- Sometimes there is a rebate to customer if additional development uses the same facilities.

Why Make Customers Pay Up-front?

- Standard rates are based on average costs
  - Without customer contribution, low-cost customers subsidize high-cost customers.
  - Customers in remote areas do not see the full cost of their location decisions without an up-front contribution.
- Utilities are at risk for cost recovery
  - If customers with high-cost hook-up leaves and is not replaced, utility may not be able to recover the cost from other customers.

What is the Rationale for a Revenue – Based Line Extension Policy?

- If hook-up is expensive, but customer will use a lot of energy, vertically-integrated utility can make up the difference with higher-than-average profits on the generation component.

- If hook-up is expensive (and would be stranded if customer left), but customer uses a lot of energy, utility can get its investment back (through energy sales) quickly.

How Have Things Changed?

OLD	NEW		
Vertically- Integrated Utility	Wires Company Only	→	Can't use profits on energy sales to offset losses on distribution
	Or		
	May be selling generation too, but with no guarantee that customer won't switch to a new supplier	→	Can't be sure of any revenues from energy sales to a given customer

With competitive generation, it would be illegal to tie distribution charges (line extension allowance) to sales of generation.

How Have Things Changed?

OLD	NEW
Distribution is a small part of of the business.	Distribution (and perhaps transmission) is everything.

- Costs are largely fixed (no fuel or purchased power)
- Revenues vary according to rate design
  - Per customer?
  - Per KW of contract capacity?
  - Per kWh?
  - Some combination?
- Need to watch cash flow carefully and minimize risk.

How Have Things Changed?

OLD	NEW
R of R Regulation	PBR

There may be a much longer
and fixed period during
which rates cannot be changed
except by a formula tied to inflation

- If there are higher than expected hook-up costs (so average distribution costs rise), the Distco may get into financial trouble.

How Have Things Changed?

OLD	NEW
Fast-growing asset base (all that new generation)	Declining asset base (unless service territory is growing rapidly)

Company officers like to run a fast-growing company.

- If customers pay up front for most new distribution, how can rate base grow?

How Have Things Changed?

Old	New
Distribution Monopoly	Distributed generation is a serious threat

Distribution assets may be the next stranded costs.

Up-front contributions by customers will reduce potential distribution stranded costs.

What do the changes imply for line extension policies?

1) A revenue test no longer makes sense.

2) A policy under which the utility pays for only a certain length of line or dollar cost (varying by voltage/class) will minimize risk.

3) Such a policy needs to be enforced (no discretion in the field).

Bottom Line:

- How much customers pay up front and how much new investment expands rate base is a question of risk management.

- The optimal strategy will depend upon what else is going on in the company.